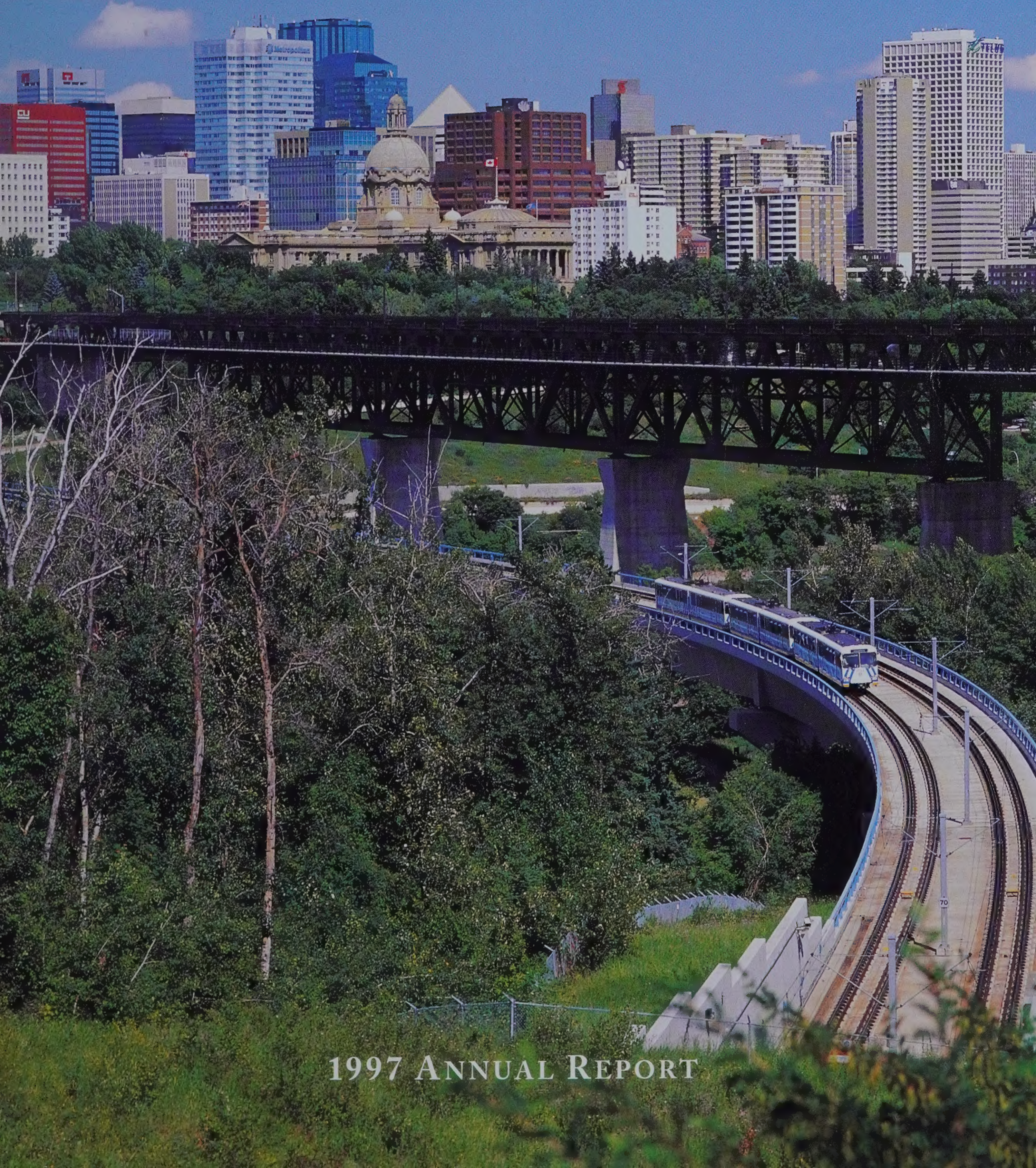
Canadian Utilities Limited

An ATCO Company



1997 Annual Report

EDMONTON, ALBERTA

Three subsidiaries of Canadian Utilities Limited — Alberta Power Limited, Northwestern Utilities Limited and Frontec Corporation — are headquartered in Edmonton. These three ATCO Group companies are major contributors to the region's strong economic growth and development.

TABLE OF CONTENTS

CANADIAN UTILITIES LIMITED

An ATCO Company

Canadian Utilities Limited is an investor-owned Alberta-based company, active in three major areas of endeavour:

ELECTRIC POWER OPERATIONS:

Canadian Utilities' subsidiaries, Alberta Power Limited, The Yukon Electrical Company Limited and Northland Utilities provide electric power generation, transmission and distribution to customers in north central Alberta and parts of the Yukon and the Northwest Territories. CU Power International Limited is an independent power producer with operations in Canada, Great Britain and Australia.

Alberta Power Limited
The Yukon Electrical Company Limited
Northland Utilities (NWT) Limited
Northland Utilities (Yellowknife) Limited
CU Power International Limited

NATURAL GAS OPERATIONS:

Through subsidiaries, Canadian Western Natural Gas and Northwestern Utilities, CU provides natural gas production, transmission and distribution to Alberta industrial, residential and commercial customers. Gas gathering, processing, storage and gas supply procurement are the key areas of operation for ATCO Gas Services Ltd.

Canadian Western Natural Gas Company Limited
Northwestern Utilities Limited
ATCO Gas Services Ltd.

TECHNICAL SERVICES & FACILITIES MANAGEMENT:

Frontec Corporation provides project management and technical services; operation and maintenance; technology transfer and training services to the defence, transportation and industrial sectors.

Frontec Corporation

Financial Highlights

Consolidated Annual Results

(Millions of Canadian Dollars except share data)

	1997	1996
Financial		
Revenues	**1,927.6**	1,813.1
Earnings attributable to Class A and Class B shares	**181.5**	171.3
Total assets	**4,090.7**	3,936.6
Class A and Class B shareholders' equity	**1,245.4**	1,195.9
Capital expenditures – net	**353.8**	257.6
Cash flow from operations	**401.6**	383.0
Class A Non-voting and Class B Common Share Data		
Earnings per share	**2.85**	2.68
Dividends paid per share	**1.56**	1.48
Equity per share	**19.66**	18.70
Shares outstanding	**63,339,685**	63,970,505
Weighted average shares outstanding	**63,714,222**	63,940,153

Consolidated Quarterly Results (1)

(Millions of Canadian Dollars except per share data)

(Unaudited)

		Three Months Ended				
		March 31	June 30	September 30	December 31	Total
Revenues	**1997**	**644.3**	**400.8**	**368.0**	**514.5**	**1,927.6**
	1996	563.0	385.5	345.8	518.8	1,813.1
Earnings attributable to Class A and Class B shares	**1997**	**65.3**	**37.7**	**26.8**	**51.7**	**181.5**
	1996	66.4	31.4	23.8	49.7	171.3
Earnings per Class A and Class B share	**1997**	**1.02**	**0.59**	**0.42**	**0.82**	**2.85**
	1996	1.04	0.49	0.37	0.78	2.68

(1) Because of seasonal fluctuations, particularly in the utility operations, quarterly earnings are not indicative of full year results.

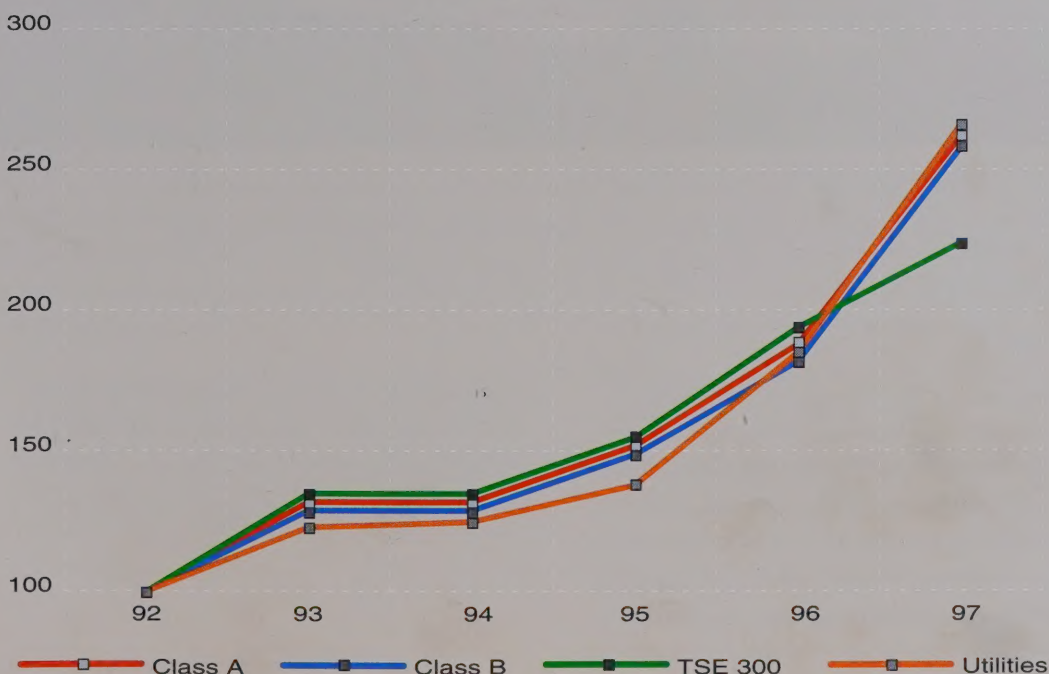
Canadian Utilities Limited
1997 Achievements

- Alberta Power Limited introduced flexible rate options for industrial customers.
- CU Power International Limited and its partner are negotiating a power purchase agreement in order to construct a 240 MW cogeneration plant at Port Alberni, B.C.
- Northwestern Utilities Limited successfully negotiated a five year rate agreement with customers in 1997 and Canadian Western Natural Gas Company Limited is negotiating long term rates with its customers in 1998.
- ATCO Gas Services Ltd. completed the construction of the Villeneuve ethane extraction plant in 1997.
- Frontec and a partner were awarded a support contract for the NATO flying training program in Canada at Moose Jaw, Saskatchewan.

FIVE YEAR TOTAL RETURN ON $100 INVESTMENT

The graph below compares the cumulative shareholder return over the last five years on the Class A non-voting shares and Class B common shares of the Corporation (assuming a $100 investment was made on December 31, 1992) with the cumulative total return of the TSE 300 Composite Index and the TSE Utilities Subindex, assuming reinvestment of dividends.

	Cumulative Return	Compound Growth Rate
CU Class A	$261	21.2%
CU Class B	$258	20.9%
TSE 300	$224	17.5%
TSE Utilities	$264	21.4%



Letter to the Share Owners

(From left to right) J.A. Campbell, Senior Vice President, Finance & Chief Financial Officer; N.C. Southern, Deputy Chairman; R.D. Southern, Chairman & Chief Executive Officer; C.O. Twa, President & Chief Operating Officer.

THE PAST

Many years ago – 1987 to be exact – your Directors chose, after much consideration, to build our Company with a new "Product Specific" group of principal operating subsidiaries, to be led by our best executives, to be governed by their own domiciled Board of Directors, and to be funded by their own balance sheet to provide sensible "Shoulder Room" for growth opportunities.

From that time on, each subsidiary has reported to a small combined Head Office known as the "Office of the Chairman" which in turn has been responsible for overall group strategy, financing and administration.

The relationship between our subsidiaries and the Office of the Chairman has become the Group's greatest strength. It is one of unusual transparency and extraordinary teamwork, and has resulted in annual success as we have deployed, in a "self actualizing" way, the best minds throughout our group to each unit's opportunities and problems created by their ever-changing markets.

As a result of our spirited dedication to this method of operating for the last ten years, our planning and business processes have constantly improved and have resulted in simple annual subsidiary plans that everyone understands... and that everyone can execute in a genuinely determined fashion.

These individual business plans are approved under a "Separate and Distinct Financial Plan" for the Group's long term objectives, which in turn is agreed to by the Board of Directors and Senior Officers during our annual strategy conferences.

What is interesting, is that while each unit's business plan changes from year to year, the overarching "Separate and Distinct Financial Plan" has not changed in ten years.

We hope it is even more interesting and rewarding for share owners to know that each and every "hard to achieve" target pertaining to earnings per share, dividends and balance sheet ratios has been achieved – every year for the last ten years.

These two budget and planning techniques blended with our special process of great transparency have produced premium results in each operating division of our enterprise.

Of course, none of our achievements of the past, nor any that we might contemplate in the future, would be possible without our executives who bring enormous personal energy to our plans and who have the ability to energize their people with such great determination, commitment and spirit.

The ATCO "Spirit" we refer to is not just words... indeed it is a fundamental philosophy of our parent company and it has become the trademark of our people and our commitment to you, our small and large share owners.

Our people understand that it is the customer alone who determines our success and we passionately believe that serving the customer to the very best of our ability is the responsibility of every employee. As a result, our people have gone far beyond what anyone thought they might do; they have paid attention to the smallest detail; they have set and strived for the highest possible standards, and they "care".

PRESENT

While it might not be for us to say, it has been a splendid decade of achievement... and 1997 was no exception!

Great detail on our operations is provided in the Management's Discussion and Analysis section of this report, so let us look at the financial results which affect your values so directly.

Canadian Utilities recorded its eighth consecutive year of increased earnings in 1997. Earnings were $181.5 million ($2.85 per share) compared to $171.3 million ($2.68 per share) in 1996.

The 1997 earnings reflect strong performance by all of the operating units and were achieved despite temperatures that were 18.7% warmer than 1996 in the Companies' main service areas. Significant factors affecting 1997 results were lower financing costs and increased sales in the Companies' electric power operations.

Cash flow from operations in 1997 was $401.6 million compared to $383.0 million in 1996.

The Board of Directors declared a first quarter dividend of 41 cents per Class A non-voting and Class B common share payable March 1 to share owners of record on February 10, 1998. This is the 26th consecutive year that the annual common share dividend has increased and reflects continuing strong financial performance.

Canadian Utilities' sustained performance over an eight year period has enhanced share owner values. The total return to share owners, including dividends and capital gain, was 38% in 1997. An investment in Canadian Utilities' shares over the five year period ending December 31, 1997 would have provided share owners with a compound growth rate of 21%.

THE FUTURE

1998 marks another year of the longest positive economic cycle in history, but it is doubtful that we will experience such favorable conditions for the next decade and it would be utterly reckless to predict with certainty that continued success will come automatically.

We do, however, bring strength to what inevitably will be a highly competitive marketplace for each of our subsidiaries.

We firmly believe that our Company is in the right business, and has the proper organization, governance, and processes for continued success… and… most importantly, we have the right people in the right jobs.

We would especially like to recognize the great leadership in the Office of the Chairman provided to the Group by our new President and Chief Operating Officer, Craighton Twa, and our Senior Vice President, Finance and Chief Financial Officer, Jim Campbell. Together with the premium executive teams and Presidents in our subsidiaries, they give us a "granite-like" base for future achievement.

Succession plans to assure a steady flow of winning executives of absolute premium characteristics from the impressive depth of our management teams are a constant imperative for your Corporate Governance – Nomination, Succession and Compensation Committee, as well as the Office of the Chairman.

In the years ahead, we are committed to sustaining for share owners our record of the past by achieving consistent earnings per share growth while at the same time making investments for value-enhancing projects in the longer term.

It has been our experience that business uncertainty such as abounds today can in fact deliver great opportunities. Our balance sheets at the core and subsidiary levels are strong, ensuring that we can take advantage of opportunities that fit our overall strategic ambitions.

Share owners should be comforted by our people's past history of achievement. Our Directors, Officers, and employees are quite capable of making "hard decisions" firmly, with fairness and absolute integrity.

We are well prepared and look forward to seizing new opportunities in each of our enterprises, taking great confidence in the ability, the knowledge, instinct and courage of our people.

On behalf of the Board of Directors,

R.D. Southern
CHAIRMAN OF THE BOARD
AND CHIEF EXECUTIVE OFFICER

N.C. Southern
DEPUTY CHAIRMAN OF THE BOARD

March 24, 1998

1997 Review of Operations

ALBERTA POWER LIMITED

CU POWER INTERNATIONAL LIMITED

NORTHWESTERN UTILITIES LIMITED & CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

ATCO GAS SERVICES LTD.

FRONTEC CORPORATION

Alberta Power has provided electric energy services to residential, commercial, industrial and farm customers for more than 70 years.

Electric Power Utility Operations

- ALBERTA POWER LIMITED
- THE YUKON ELECTRICAL COMPANY LIMITED
- NORTHLAND UTILITIES (NWT) LIMITED
- NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED

Canadian Utilities provides electric utility service through four operating companies, Alberta Power Limited and its subsidiaries, The Yukon Electrical Company Limited, Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

These companies supply electric utility service to customers in 355 communities in Alberta, the Yukon, Northwest Territories, Saskatchewan and British Columbia.

In 1997, combined sales increased by 3.4% to 10,089 million kilowatt hours on a sales base that is made up of 86% industrial and commercial customers, 9% residential customers and 5% farm. Two hundred and sixty-two industrial customers were added in Alberta in 1997, mainly because of heightened oil sands and oil field activity.

Capital spending for Alberta Power totalled $116 million including $69 million on distribution projects, $22.5 million on transmission projects and upgrades and $20.5 million for generation upgrades and maintenance.

In 1997, Alberta Power received an Alberta Energy and Utilities Board ("EUB") decision approving its revenue requirement and rate of return on common equity for 1996. In January 1998 the EUB reviewed and approved a 1997 negotiated rate settlement. The EUB reaffirmed Alberta Power's rates as prudent and appropriate, making only minor adjustments.

Amidst industry changes resulting from deregulation, Alberta Power remains committed to providing safe, reliable, affordable electricity. The company has made progress on various initiatives to strengthen service to customers. Highlights from 1997 include:

- *Continuing installation of automatic metre reading. More than 46,000 electric metres have been installed. This system reads metres over the power lines, eliminating estimated and manual metre reading costs and helping to keep costs low.*
- *Contracting to read more than 2,400 water metres for three municipalities, using automatic metre reading technology. The company is running pilot projects in other communities.*
- *Introducing a new rate that allows industrial customers to monitor the hourly pool price for electricity in Alberta and adjust their consumption accordingly. This pool price is set hourly on a spot market that matches demand and supply in the province.*

Alberta Power has made good progress towards improved customer service, streamlining its operations to gain greater efficiencies. The company's sales have increased by 2,254 million kilowatt hours since 1992. During that same period staffing levels decreased 15%. As a result of these efforts, sales per employee have increased by more than 50% in five years.

New projects for Alberta Power in 1998 will continue to enhance customer service. They include establishing a new company to address the generation needs of small industrial and commercial customers. A centralized customer assistance facility will be established later in the year to improve customer service and reduce costs.

The Yukon Electrical Company Limited, which has been in business for 96 years, continues to see customer growth. The company served 15,106 customers in 1997, a 1.9% increase over last year. Of these customers, 1,845 are in the service area of Yukon Energy Corporation and are not included in the consolidated customer totals in this report.

In 1997, The City of Yellowknife explored the feasibility of purchasing the Northland Utilities (Yellowknife) distribution franchise midway through its term, but did not pursue the matter after a public review and an asset valuation study.

Although mining activities were reduced due to lower mineral prices, Northland Utilities experienced a 0.8% increase in their customer base, for a total of 8,853 at year-end.

The 180 MW Osborne cogeneration electric power station located near Adelaide, South Australia is currently under construction with commissioning expected in July 1998.

• Adelaide

Electric Power
Independent Power Production

CU POWER INTERNATIONAL LIMITED

CU POWER INTERNATIONAL LIMITED ("CUPIL") HAS ESTABLISHED A SOLID REPUTATION AS A DEVELOPER, PROJECT MANAGER, OWNER AND OPERATOR OF INDEPENDENT POWER PROJECTS AND CURRENTLY OPERATES OVER 1,300 MW OF NON-REGULATED GENERATING CAPACITY.

CANADA

CUPIL commissioned its first independent power project in 1993 in a joint venture with Westcoast Power Inc. This 120 MW cogeneration plant in Taylor, B.C. exceeded its availability targets in 1997. The plant sells electricity to BC Hydro under a 20 year agreement and steam to an adjacent gas plant owned by Westcoast Energy Inc.

In September 1997, the Premier of British Columbia announced his government's approval for CUPIL and PanCanadian Petroleum Limited to negotiate a power purchase agreement with BC Hydro. The power would be supplied by a 240 MW cogeneration plant to be constructed adjacent to MB Paper Limited's Alberni Specialties Mill on Vancouver Island, which would also sell steam to the mill. The cogeneration plant, owned jointly by CUPIL and PanCanadian, is estimated to cost $200 million.

During 1997, CUPIL and Amoco Power Resources Corp. commenced construction on a jointly owned 85 MW cogeneration project at Amoco's Primrose Heavy Oil operation in northeast Alberta. The exhaust heat and a portion of the electricity will be sold to Amoco and the balance of the electricity will be sold into the Power Pool of Alberta. Completion is scheduled for the last quarter of 1998.

AUSTRALIA

Construction of the 180 MW cogeneration plant in Osborne, South Australia continued with an anticipated completion date in the third quarter of 1998. CUPIL is the construction manager of this joint venture with Boral Energy Limited. The plant will sell electricity to ETSA Corporation under a 20 year agreement and steam to an adjacent soda ash plant owned by Penrice Soda Products Pty Ltd.

UNITED KINGDOM

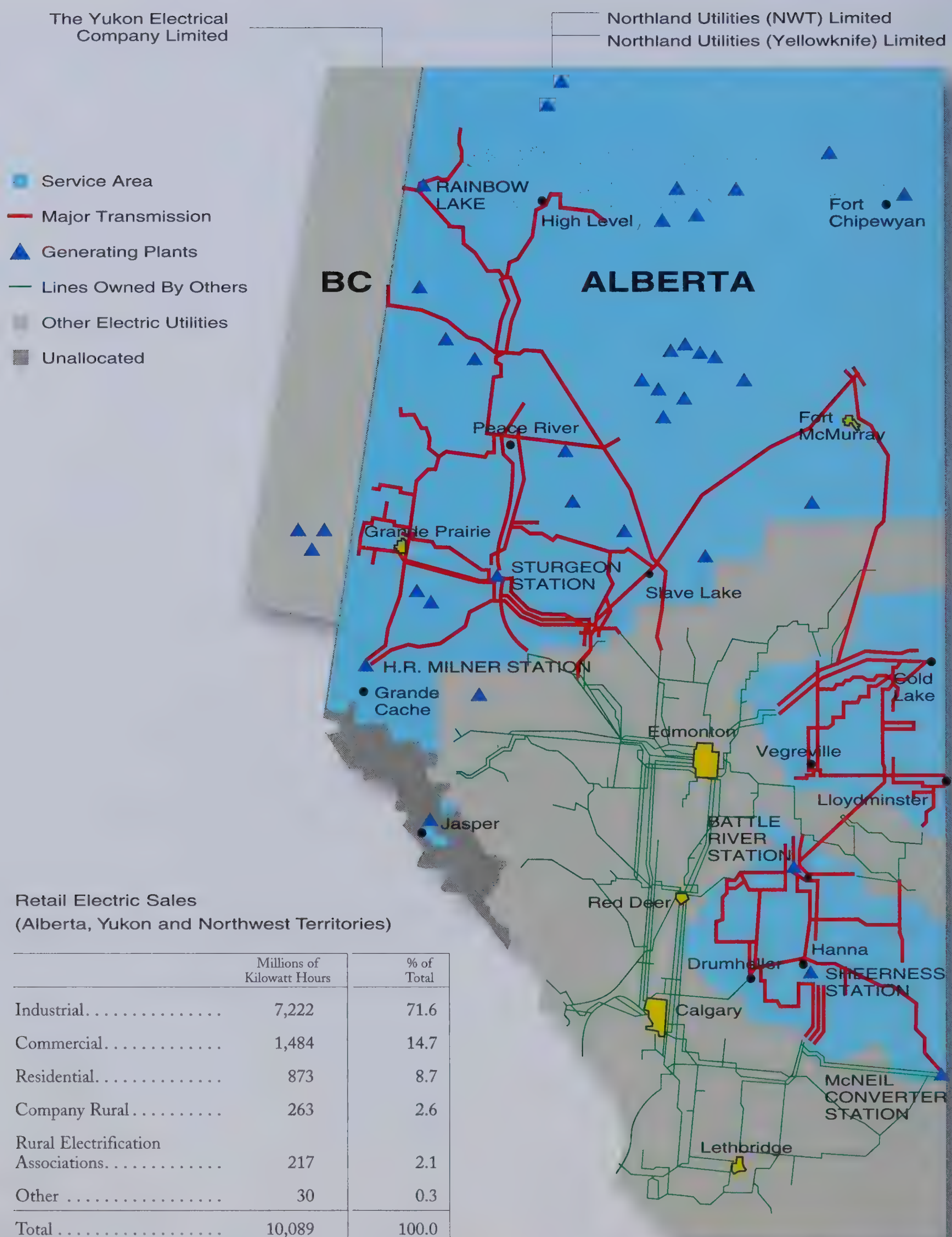
CUPIL is the managing owner of the 1,000 MW gas fired combined cycle Barking power station located on the River Thames east of London, England. CUPIL led the project's development and was responsible for the owners' engineering role during construction. CUPIL's managers are responsible for the station's operation. The Barking station was commissioned in 1995 and surpassed its availability targets in both 1996 and 1997.

In 1997, Barking Power Limited applied to the United Kingdom Department of Trade to expand the station by the addition of a 123 MW turbine for peaking purposes and a 4 x 7 MW turbine for Black Start purposes. At year end, the application was still under review.

The Heathrow Cogeneration Plant, purchased in July 1995 by a joint venture of CUPIL and London Electricity plc, met its availability targets during 1997. The plant, which has a 14 MW gas fired turbine and a 40 MW boiler, supplies electricity and hot water to British Airports Authority plc under a 15 year contract.

Independent power development opportunities in selected domestic and international markets will continue to be evaluated for the company's growth in 1998 and beyond.

Electric Power System Map

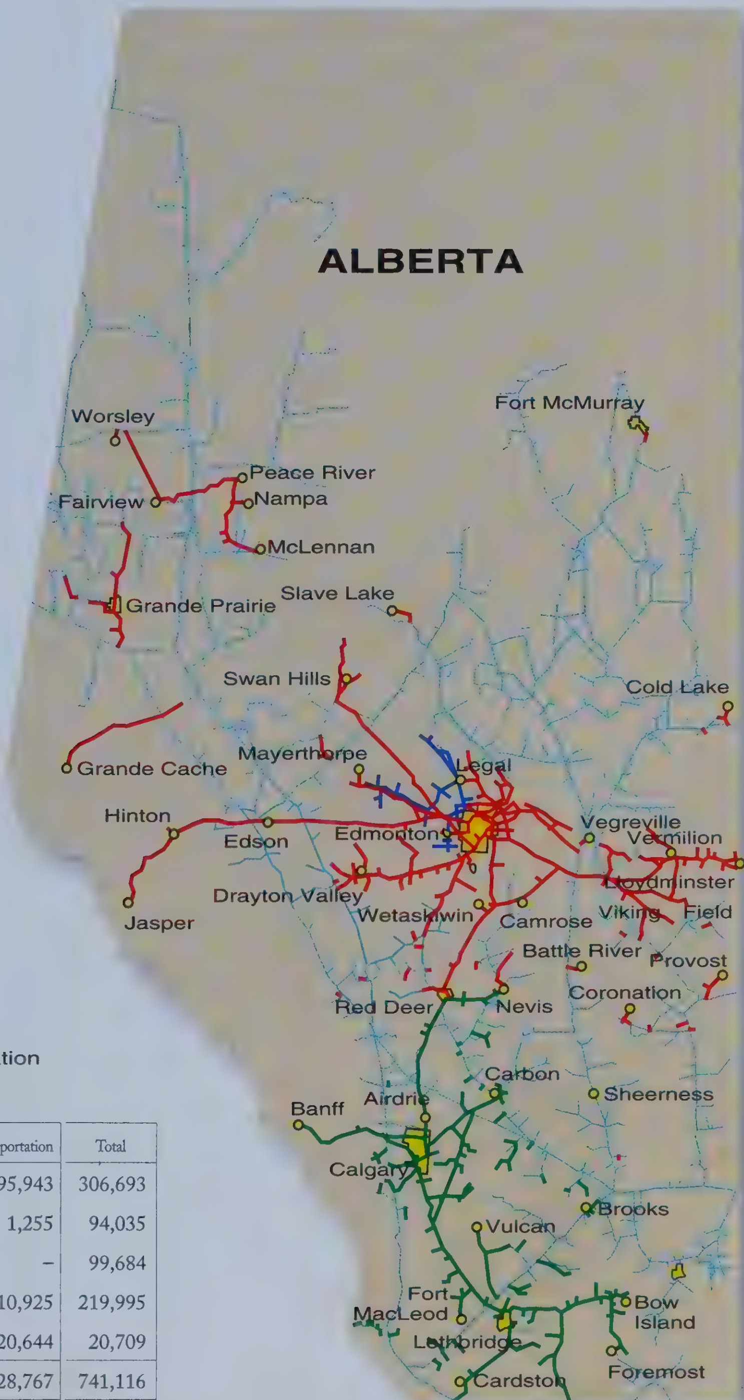


Retail Electric Sales
(Alberta, Yukon and Northwest Territories)

	Millions of Kilowatt Hours	% of Total
Industrial	7,222	71.6
Commercial	1,484	14.7
Residential	873	8.7
Company Rural	263	2.6
Rural Electrification Associations	217	2.1
Other	30	0.3
Total	10,089	100.0

Natural Gas System Map

- Northwestern Utilities
- Canadian Western Natural Gas
- ATCO Gas Services Ltd.
- Other Major Gas Pipelines



Natural Gas Sales and Transportation (Terajoules)

	Sales	Transportation	Total
Industrial	10,750	295,943	306,693
Commercial	92,780	1,255	94,035
Residential	99,684	–	99,684
Other	9,070	210,925	219,995
Affiliates	65	20,644	20,709
Total System Throughput	212,349	528,767	741,116

Pipeline installation for Northwestern Utilities' transmission debottlenecking projects in 1997.

Natural Gas Utility Operations

- Canadian Western Natural Gas Company Limited
- Northwestern Utilities Limited

Canadian Western and Northwestern provide natural gas utility service to customers across Alberta. Combined, the two subsidiaries delivered over 700 petajoules ("PJ") of natural gas in 1997, an increase of 2% over 1996, despite warmer than normal temperatures.

In 1997, Northwestern, which serves north central Alberta including the City of Edmonton, exceeded 500 PJ of throughput for the first time in its history, despite the month of December which was the warmest on record. Strong growth throughout Northwestern's service territory resulted in over 7,000 new customers being added to the system with over 389,000 customers served at year end.

Canadian Western's throughput was 238 PJ in 1997. During the year, the company added in excess of 11,000 customers resulting in 367,515 customers being served in 115 communities throughout central and southern Alberta, including the City of Calgary.

Northwestern and Canadian Western invested approximately $140 million in capital to increase system capacity, debottleneck existing pipelines, connect new customers and make general improvements to the transmission and distribution pipeline systems.

Canadian Western and Northwestern continued to promote natural gas appliances and natural gas as a transportation fuel. In June, Canadian Western won the Canadian Gas Association marketing Excellence Award for its natural gas shuttle bus demonstration program with Calgary Transit. The program showcased the financial and environmental benefits of natural gas powered public transit buses.

In an effort to build more businesslike relationships with customers and to avoid the high cost and delay associated with contested regulatory hearings, Northwestern achieved two negotiated settlements with its customers in 1997. The first was a settlement with producer and industrial customers who use Northwestern's system to transport gas they own. This settlement was effective January 1, 1998 and resolves rate and service issues through to 2002. The second is a settlement with residential, commercial and institutional customers who buy their gas from Northwestern. This settlement, also covering five years, provides for increases in the cost of service rate that are predictable and lower than expected inflation over the period.

In early 1998, Canadian Western entered into negotiations with its customers for future rates, after five years of cost of service rate stability due in large part to a strong emphasis on productivity and efficiency.

A continued strong emphasis on safety resulted in reduced frequency rates for both lost time personal injuries and preventable vehicle accidents.

Canadian Western and Northwestern are very conscious of the public concern about the environmental impact associated with the use of fossil fuels, and therefore all reasonable steps are taken to operate in a fashion that minimizes this impact. In 1997, Northwestern was awarded the Canadian Gas Association Environmental Award for implementing and training staff about its Environmental Management System.

Both gas companies continued to address targets for increased productivity. Two significant initiatives were carried out in 1997. A corporate head office restructuring was undertaken to improve efficiencies and a restructuring within each of the gas companies resulted in staff reductions. In 1998 both companies will continue to look for opportunities to streamline operations without sacrificing quality customer service.

The Carbon Storage Facility, with a capacity of 43.5 PJ (40 bcf), is an integral part of the Alberta Market Centre™. ATCO Gas Services Ltd. markets the storage capacity and manages the operation and maintenance of the facility.

Natural Gas Gathering, Processing & Services

■ ATCO GAS SERVICES LTD.

ATCO Gas Services ("AGS") underwent significant changes in 1997. A new senior management team initiated a thorough evaluation of the company and its business areas. The result was a redefined company with focused services, improved productivity and responsiveness.

Midstream Services (gas gathering and processing) and The Alberta Market Centre™ (gas storage, hub and management services) are now AGS' two key areas of operation.

In 1997, high ethane prices early in the year, coupled with good throughput in AGS' gas plants, were major factors in the company's record earnings.

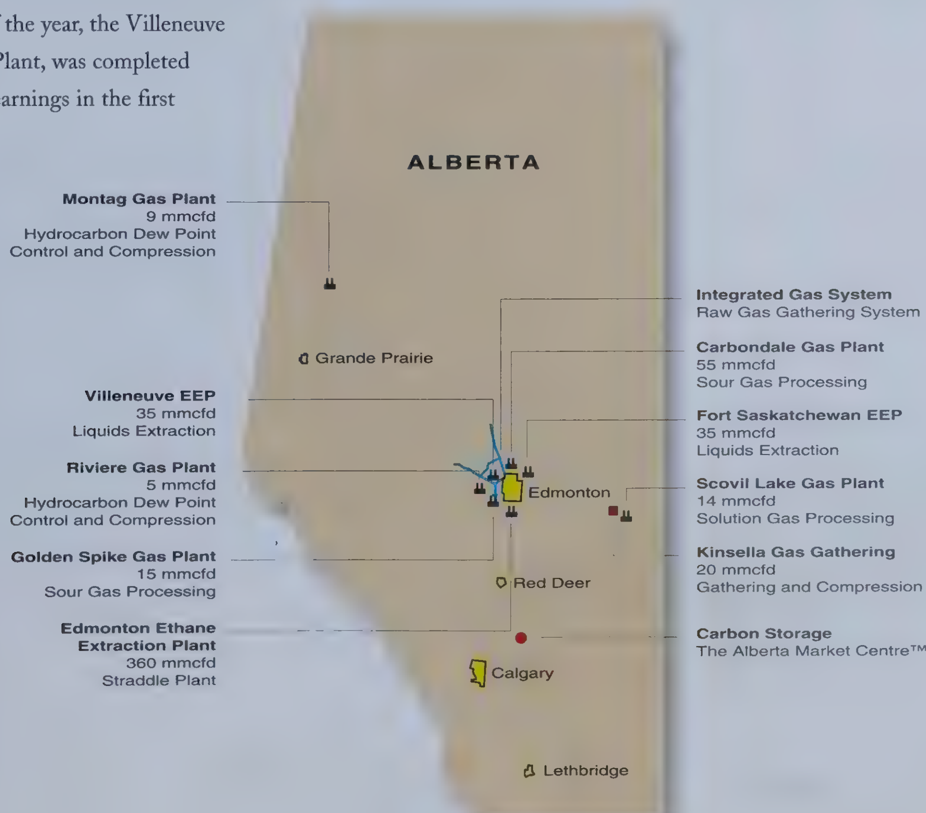
The main project of the year, the Villeneuve Ethane Extraction Plant, was completed and contributed to earnings in the first quarter of 1997.

In August 1997, AGS expanded the capacity of the Montag Gas Plant, located in the Peace River Arch region, to allow area producers to access markets both on the Northwestern Utilities Limited system and the Nova Gas Transmission Ltd. system.

AGS' Scovil Lake facility was commissioned in November 1997 to process solution gas from PanCanadian Petroleum Limited's Wainwright West oil operations.

The Alberta Market Centre™, including the Carbon storage facility, continued to offer innovative gas storage and gas management services to both external and internal customers.

1998 promises to be a threshold year for AGS. The midstream business in western Canada is highly competitive; however, AGS is well positioned to capitalize on midstream opportunities, based on its existing facilities and its focus to bring value to its producer clients.



Frontec and its partner manage and operate the radar system for the U.S. Air Force throughout Alaska. This system, like Canada's North Warning System, also provides over-flight information for the commercial aviation sector.

Technical Services & Facilities Management

■ FRONTEC CORPORATION

FRONTEC IS A LEADER IN TECHNICAL SERVICES AND FACILITIES MANAGEMENT FOR THE DEFENCE, AIR TRANSPORTATION AND INDUSTRIAL SECTORS. FRONTEC IS AN ISO 9002 CERTIFIED COMPANY, AN INTERNATIONAL STANDARD FOR QUALITY ASSURANCE WHICH PROVIDES A HIGH LEVEL OF ACCREDITATION FOR FRONTEC AS THE COMPANY PURSUES INTERNATIONAL BUSINESS OPPORTUNITIES.

Frontec continued to operate and maintain more than 70 radar and logistics support sites which make up the North Warning System in Canada and the Alaska Radar System in the United States.

In 1997, Frontec and other members of a distinguished bi-nation team were awarded a high priority U.S. Department of Defence contract. Frontec's responsibility is for site preparation, installation, integration and testing, field engineering and training at the upgrade of five radar processing computer sites in North America.

Frontec also expanded the scope of its Iris contract in 1997 from the original installation of 6,000 digital radios in Canadian Armed Forces vehicles to include the production of cables and interface panels on these same vehicles.

Frontec's Portage la Prairie contract to support military training operations has served as a model for Frontec and its partner Bombardier to negotiate the multi-million dollar support contract for the NATO Flying Training program in Canada at Moose Jaw, Saskatchewan in 1998.

Frontec was awarded a five year contract to manage and operate the City of North Bay airport beginning in January 1998. Frontec also continues to operate the municipally owned airport at Castlegar, BC.

NorthwestTel awarded Frontec as principal subcontractor and their partners, Northern Aboriginal Services Co. ("NASCO"), a ten year multi-million dollar contract to operate and maintain 154 power generating systems throughout the Northwest Territories, northern British Columbia and the Yukon. Frontec also operates and maintains the power generating plant at Elmendorf Air Force Base in Alaska.

Frontec and its northern partners continued their venture, Uqsuq Corporation. This company stores and distributes fuel in Iqaluit, off-loads ships, maintains a tank farm, refuels aircraft and provides home delivery of fuel.

Torngait Services Inc., a partnership with the Labrador Inuit Development Corporation, remains poised to provide transportation, logistics and support services in the Voisey's Bay region.

Property Management, Security and the newly acquired ATCO Travel are expected to be solid performers in the Frontec group for 1998.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of financial condition and results of operations of the Corporation for the years ended December 31, 1997 and 1996 should be read in conjunction with the Corporation's audited consolidated financial statements and related notes contained in this annual report.

The Corporation's annual audited financial statements are consolidated from four business segments: electric power, natural gas, technical facilities management, and corporate and other (refer to Note 13 to the Consolidated Financial Statements). Transactions between segments are eliminated in all reporting of the Corporation's consolidated financial information.

RESULTS OF OPERATIONS

Consolidated Operations

Segmented revenues and earnings before income taxes for the years 1996 and 1997 were as follows:

	Revenues		Earnings	
(Millions of Canadian Dollars)	**1997**	1996	**1997**	1996
Electric Power	**837.7**	811.7	**206.5**	186.4
Natural Gas	**994.7**	912.6	**143.3**	155.4
Technical Facilities Management	**98.2**	89.3	**11.2**	11.4
Corporate and Other	**12.3**	14.7	**1.0**	-
Consolidated (1)	**1,927.6**	1,813.1	**362.0**	353.2

Notes:

(1) Inter-segment transactions have been eliminated from the consolidated information.

(2) Certain 1996 comparative figures have been reclassified to conform with the current year's presentation.

Earnings per share increased in 1997 to $2.85 from $2.68 in 1996. Return on common equity was 14.8%, unchanged from 1996.

Electric Power

Earnings Before Income Taxes

Earnings before income taxes from electric power operations for 1997, which amounted to 57.0% of consolidated earnings before income taxes of the Corporation, increased by $20.1 million or 10.8% to $206.5 million. The increased earnings were largely attributable to lower financing costs, higher industrial sales by Alberta Power Limited ("APL"), mainly in the oilsands and oilfield sectors, higher availability of the Barking power station and an increase in the average Sterling exchange rate.

Revenues

Revenues in 1997 increased by $26.0 million or 3.2% to $837.7 million. This increase was primarily the result of higher APL industrial sales, mainly in the oilsands and oilfield sectors, higher availability of the Barking power station and an increase in the average Sterling exchange rate.

Operating Expenses

Operating expenses for 1997 increased by $17.9 million or 4.7% to $402.6 million. The increase was primarily due to higher fuel costs at the Barking power station.

Fuel costs in APL are mostly for coal supply. To protect against volatility in coal prices, APL owns or has committed under long term contracts sufficient coal supplies for the anticipated lives of its coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

Fuel costs in the Corporation's non-regulated electric power operations are for natural gas supply. The Corporation obtains its natural gas supplies under long term contracts to protect against volatility in natural gas prices. The contract price for natural gas is passed through to the purchasers of the electricity. The Corporation also has the opportunity to purchase natural gas supplies under short term contracts and does so when it is advantageous.

Depreciation and Depletion

Depreciation and depletion expenses increased by $0.3 million or 0.3% to $113.4 million in 1997. This increase was primarily a result of capital additions during 1996 and 1997, partially offset by the change to lower depreciation rates in accordance with the 1996 decision of the Alberta Energy and Utilities Board ("EUB") for APL.

Financing Charges and Other

In 1997, financing charges and other declined by $12.3 million or 9.6% to $115.2 million, primarily as a result of lower dividends on retractable preferred shares and lower interest expense on long term debt.

Regulatory Matters

As required under the Electric Utilities Act ("EUA"), APL filed a general rate application with the EUB on October 31, 1995 for the 1996 test year seeking, among other things, approval for wholesale tariffs for each of generation and transmission as well as retail rates for distribution. On October 31, 1997, the EUB issued its decision which, among other things, approved a rate of return of 11.25% on the portion of rate base considered to be financed by common equity and confirmed APL's capital structure without any adjustments or amendments. A negotiated settlement for 1997 customer rates filed with the EUB on October 31, 1997 was approved by the EUB on January 30, 1998. The impact of these two decisions has been reflected in the Corporation's 1996 and 1997 financial statements.

On January 16, 1998, APL commenced negotiations with its customers to establish customer rates for 1998. Any settlement reached through these negotiations will have to be submitted to the EUB for approval prior to implementation.

Business Outlook

Utility Operations In March 1997, APL experienced an outage at two 30 megawatt generating units at its Battle River generating station. On October 10, 1997, APL applied to the EUB for temporary suspension of its obligation to supply electricity from these units. On November 18, 1997, temporary suspension was approved by the EUB on an interim refundable basis effective October 1, 1997 and lasting until the generating units are returned to service or until the issuance of a final order regarding the application. APL is currently working with its customers to reach an agreement for both the temporary suspension application and the discontinuance of operations, dismantling and removal of the generating units.

As part of the electric industry review leading to the implementation of the EUA, it was agreed that a study, commencing in 1996, would be conducted into the feasibility of retail customers buying their incremental electric energy requirements from suppliers other than their local electric utility. Currently only wholesale customers, namely distribution utilities, are allowed to purchase the electric energy required to meet customer needs in excess of the amounts supplied by existing generation from the supplier of their choice. A committee consisting of government, industry and customer representatives was established to review this matter and discussions are continuing.

In late 1997, APL announced that it would be streamlining its operations so that it will be better prepared to meet the challenges of a more competitive environment in the future. As a result of this process, APL has reduced staffing requirements by approximately 7%.

Capital Expenditures Capital expenditures in the Corporation's electric utility operations were $122.4 million in 1997 and are expected to be approximately $175 million in 1998. Capital expenditures in non-regulated electric power operations were $66.6 million in 1997 and are expected to be approximately $40 million in 1998 for projects under construction.

Natural Gas

Earnings Before Income Taxes

Earnings before income taxes from natural gas operations for 1997, which amounted to 39.6% of consolidated earnings before income taxes of the Corporation, decreased by $12.1 million or 7.8% to $143.3 million. Earnings decreased primarily as a result of temperatures warmer than 1996, partially offset by lower interest expense and lower dividends on retractable preferred shares. Temperatures in 1997 were 1.0% warmer than normal, whereas temperatures in 1996 were 20.3% colder than normal.

Revenues

Revenues in 1997 increased by $82.1 million or 9.0% to $994.7 million. The primary reason for the increase was the recovery of higher natural gas supply costs and customer growth, partially offset by the impact of warmer temperatures which were 18.7% warmer than in 1996.

Operating Expenses

Operating expenses for 1997 increased by $95.6 million or 15.3% to $719.0 million. This increase was primarily due to higher natural gas supply costs. These costs increased primarily due to higher natural gas prices and increased sales volumes, mainly due to customer growth. These increased costs were partially offset by the impact of warmer temperatures which reduced sales per customer. The amount of natural gas supply costs recorded as an expense is based on the forecast cost of natural gas included in customer rates. Any variances from forecast are deferred until the EUB approves revised rates to either refund or collect the variance. As a consequence, changes in natural gas supply costs have a negligible effect on the Corporation's earnings.

Depreciation and Depletion

Depreciation and depletion expenses rose $6.9 million or 9.7% to $77.8 million in 1997, primarily as a result of capital additions during 1996 and 1997.

Financing Charges and Other

In 1997, financing charges and other decreased by $8.3 million or 13.2% to $54.6 million. The decrease resulted from lower interest expense and lower dividends on retractable preferred shares.

Business Outlook

Utility Operations On May 15, 1997, Northwestern Utilities Limited ("NUL") filed with the EUB a negotiated settlement for 1997 customer rates for residential, commercial and institutional customers and a five year agreement with industrial and producer transportation customers. The EUB approved this settlement on October 30, 1997. The settlement resulted in no change to existing rates for 1997. Industrial and producer transportation rates and terms and conditions of service changed on January 1, 1998. The new rates are substantively different from the rates previously in effect, consisting of a receipt charge for natural gas received onto the NUL system and a delivery charge for deliveries from the NUL system. The previous rate structure was based on point-to-point service which provided less flexibility to customers. This agreement enhances NUL's transmission service by significantly reducing dual tolling for producers and by addressing industrial by-pass concerns.

On December 15, 1997, NUL filed an application with the EUB for approval of a five year negotiated settlement which would establish cost of service rates and terms and conditions of service for residential, commercial and institutional customers through 2002. This settlement is subject to EUB approval.

On December 5, 1997, Canadian Western Natural Gas Company Limited ("CWNG") commenced negotiations with customers to establish customer rates for 1998, as well as for the recovery of natural gas supply costs. At the request of the EUB, the negotiations will include a review of CWNG's 1997 capital structure and return on common equity. Any settlement reached through these negotiations will have to be submitted to the EUB for approval prior to implementation.

In late 1997, NUL and CWNG announced that they would be streamlining their operations so that they would be better prepared to meet the challenges of a more competitive environment in the future. As a result of this process, NUL and CWNG have reduced staffing requirements by approximately 11%.

Capital Expenditures Capital expenditures in the Corporation's natural gas utility operations were $144.4 million in 1997 and are expected to be approximately $140 million in 1998. Capital expenditures in ATCO Gas Services Ltd. ("AGS") were $9.2 million in 1997. AGS is currently pursuing a number of new projects in western Canada.

Technical Facilities Management

Earnings before income taxes from technical facilities management in 1997 declined by $0.2 million or 1.8% to $11.2 million, primarily as a result of lower earnings from the North Warning System contract, partially offset by higher earnings from other projects.

Corporate and Other

Earnings before income taxes from the corporate and other segment were $1.0 million in 1997, compared to nil in 1996.

Income Taxes

Income taxes decreased by $4.7 million or 2.7% to $168.1 million as a result of lower dividends on retractable preferred shares and the introduction of the new Canadian Institute of Chartered Accountants income tax standard in 1997 (refer to Note 2 to the Consolidated Financial Statements).

LIQUIDITY AND CAPITAL RESOURCES

Cash provided from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term debt, preferred shares and common equity. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

It is the policy of the Corporation to pay dividends quarterly on its Class A non-voting and Class B common shares. In 1997, the Corporation increased the dividends on Class A non-voting and Class B common shares by $0.08 per share. During the period 1993 to 1996, the Corporation had increased the dividends by $0.02 per share per year. The matter of an increase in the quarterly dividend is addressed by the board of directors in the first quarter of each year. For the first quarter of 1998, the quarterly dividend payment has been increased by $0.02 to $0.41 per share. The payment of any dividend is at the discretion of the board of directors and depends on the financial condition of the Corporation and other factors. Since its inception as a holding company in 1972, the Corporation has increased its annual common share dividend for 26 consecutive years.

Cash from operations increased by $18.6 million to $401.6 million in 1997, primarily due to higher earnings attributable to Class A non-voting and Class B common shares and lower current income taxes.

On April 29, 1997, the Corporation filed a Notice of Intention to make a Normal Course Issuer Bid for the purchase of up to 5% of its outstanding Class A non-voting shares during the period May 2, 1997 to May 1, 1998. As at December 31, 1997, 659,220 shares had been purchased at a cost of $24.8 million.

Investing increased from $167.2 million in 1996 to $318.4 million in 1997, primarily as a result of higher capital expenditures during 1997 and the sale of ATCOR Resources Ltd. in 1996. Excluding the one-time impact of the sale of ATCOR Resources Ltd. for $56.2 million on February 1, 1996 and the related purchase of assets for $14.6 million, investing amounted to $208.8 million in 1996.

Investment in utility property, plant and equipment was $266.8 million in 1997 compared to $207.9 million in 1996. Expenditures for property, plant and equipment in non-regulated operations were $80.1 million in 1997, versus $44.4 million in 1996. Total expenditures for 1998 are expected to be approximately $320 million for utility operations and approximately $40 million for non-regulated operations.

To finance 1997 utility operations, including the redemption of $56.3 million of long term debt having interest rates ranging from 8.95% to 17.5% and $109.5 million of preferred shares having dividend rates ranging between 4.25% and 8.0%, the Corporation issued $68.0 million of long term debt with an interest rate of 5.42% and $110.0 million of preferred shares with a dividend rate of 4.66%.

CU Power Generation Limited entered into a £50.0 million (approximately $117.9 million) credit agreement with a Canadian chartered bank on January 31, 1997. The Corporation has provided a guarantee of all advances to be made under this agreement. As at December 31, 1997, no funds had been advanced.

CU Power Canada Limited is currently negotiating a $50 million long term credit agreement with a Canadian chartered bank. This facility will be secured by certain assets within the Corporation's non-regulated electric power group.

In December 1996, AGS entered into a $25.0 million credit agreement with a Canadian chartered bank. The Corporation has provided a guarantee of all advances made and to be made under this agreement. As at December 31, 1997, $14.5 million had been advanced.

In December 1996, the Corporation and a Canadian chartered bank entered into a $60.0 million credit agreement. As at December 31, 1997, no funds had been advanced under this agreement.

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

During 1997, Canadian Bond Rating Service Inc. reaffirmed the ratings on the Corporation's Debentures and Medium Term Note Debentures at A+ and on commercial paper and preferred shares at A-1+ and P-1, respectively. Dominion Bond Rating Service Limited reaffirmed the Corporation's debt, commercial paper and preferred share ratings at AA (low), R-1 (middle) and Pfd-1, respectively.

Future income tax liabilities of $104.0 million at December 31, 1997 are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences reverse through the settlement of liabilities and realization of assets.

Business Risks

Utility Operations

The Corporation's utility operations are subject to the normal risks faced by regulated utility companies. These risks include the approval by the EUB of customer rates which permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

The business risks of APL have changed with the implementation of the EUA. There is now more forecast risk as each electric utility is exposed to the forecasts of other electric utilities in Alberta as well as the requirement to independently forecast province-wide generation output and pool prices. There is not expected to be a significant impact to earnings given APL's ability to manage these risks.

It is expected that there will be further changes in the electric utility industry in Alberta. The government of Alberta has indicated that it intends to pursue a direction, similar to that developing in other jurisdictions, whereby generation is completely deregulated and retail competition is available. This direction will result in changes to APL's business risk, both at the generation level and in the distribution and retail businesses. It is anticipated that APL's transmission activities will continue to be regulated. APL, along with other industry participants, continues to be involved in discussions with the government of Alberta regarding the details of this deregulation process and proposed legislation.

Non-Regulated Operations

The Corporation's non-regulated operations are outside its traditional utility businesses, but are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its utility operations.

The Corporation's non-regulated operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which the Corporation operates. The Corporation has attempted to limit its risks by entering into long term contracts with purchasers for the output of projects and with key suppliers. In all independent power production undertakings to date, with the exception of the 85 megawatt Primrose Project currently under construction, risks in respect of fuel and energy prices have by contract been agreed and allocated to the purchasers of the electric energy, and the Corporation to date has not assumed any risks in this regard. The Corporation has financed its major non-regulated operations, with the exception of the Primrose Project, on a non-recourse basis, whereby the lender's recourse in the event of default is limited to the business and assets of the project in question and to the Corporation's equity therein, and not to the business and assets of the Corporation as a whole.

The Corporation expects to finance its share of the Primrose Project through a long term bank credit facility and from cash on hand. To avoid assuming the price risk on the electricity sold to the Alberta power pool, the owners are negotiating long term contracts with specific customers to fix the price of this electricity.

Year 2000

Since 1995, the Corporation has been engaged in Year 2000 compliance risk assessment, conversion and testing for its critical administrative and operational computer systems. Work on administrative systems, software conversion and testing is now over 50% complete with critical financial and customer service systems already converted, tested and in operation. The risk assessment and testing of embedded operational systems is at an earlier stage as suppliers' compliance commitments have not yet been received. Year 2000 compliance projects are being managed at executive levels and are on schedule for the replacement/upgrading and testing, by mid 1999, of all critical hardware and software. The Year 2000 costs, both incurred to date and expected to be incurred in the future, are not expected to be material.

Hedging

It is the policy of the Corporation to use financial instruments to reduce specific risk exposures and not to hold these instruments for trading purposes.

The Corporation has entered into several contracts in order to reduce interest rate, foreign exchange and commodity price risk. The financial impact of these contracts is not material and the counterparty in each transaction is a major financial institution or a significant industry participant.

March 4, 1998

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgements and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management depends upon internal accounting control systems to meet its responsiblity for reliable and accurate reporting. These control systems are subject to periodic review by the Corporation's internal auditors.

Price Waterhouse, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee comprised of one management and four non-management directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and financial matters, to gain assurance that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee.

J.A. Campbell
SENIOR VICE PRESIDENT, FINANCE
AND CHIEF FINANCIAL OFFICER

K.M. Watson
VICE PRESIDENT,
CONTROLLER

Auditors' Report

TO THE SHAREHOLDERS OF CANADIAN UTILITIES LIMITED

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 1997 and 1996 and the consolidated statements of earnings and retained earnings and changes in cash position for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards required that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 1997 and 1996 and the results of its operations and the changes in its cash position for the years then ended in accordance with generally accepted accounting principles.

Price Waterhouse.
Chartered Accountants

Calgary, Canada
February 6, 1998

Consolidated Statement of Earnings and Retained Earnings

(Millions of Canadian Dollars except per share data)

Year Ended December 31

	Note	1997	1996
Revenues		$1,927.6	$1,813.1
Costs and expenses			
Natural gas supply		400.8	311.1
Fuel and purchased power		193.8	175.6
Operation and maintenance		510.5	500.8
Depreciation and depletion		192.7	186.0
Franchise, property and other taxes		103.9	98.6
		1,401.7	1,272.1
Financing charges and other			
Interest expense – recourse debt		138.6	150.4
– non-recourse debt		34.1	30.8
Dividends on retractable preferred shares		18.6	27.8
Allowance for funds used		(6.7)	(6.6)
Interest and other income		(20.7)	(14.6)
		163.9	187.8
Earnings before income taxes		362.0	353.2
Income taxes	2	168.1	172.8
Net earnings		193.9	180.4
Dividends on non-retractable equity preferred shares		12.4	9.1
Earnings attributable to Class A and Class B shares		181.5	171.3
Retained earnings at beginning of year		682.0	605.8
		863.5	777.1
Dividends on Class A and Class B shares		99.5	94.5
Direct charges to retained earnings	3	26.6	0.6
Retained earnings at end of year		$ 737.4	$ 682.0
Earnings per Class A and Class B share		$ 2.85	$ 2.68
Dividends paid per Class A and Class B share		$ 1.56	$ 1.48

Consolidated Balance Sheet

(Millions of Canadian Dollars)

	Note	December 31 1997	1996
ASSETS			
Current assets			
Cash and short term investments	9	$ 56.2	$ 34.6
Accounts receivable		294.3	282.8
Inventories		87.6	68.9
Deferred natural gas costs		(1.6)	34.9
Prepaid expenses		15.1	9.8
		451.6	431.0
Property, plant and equipment	4	3,598.6	3,474.4
Deferred financing charges		12.3	14.3
Other assets		28.2	16.9
		$4,090.7	$3,936.6
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Bank indebtedness		$ 11.8	$ –
Accounts payable and accrued liabilities		231.9	225.8
Accrued interest and dividends		28.7	30.6
Income and other taxes payable		50.0	75.3
Long term debt due within one year – non-recourse	5	16.2	15.2
		338.6	346.9
Future income taxes	2	104.0	38.1
Unearned revenues		18.8	19.8
Other deferred credits		15.8	20.2
Notes payable	6	5.3	3.9
Long term debt – recourse	5	1,419.3	1,407.0
– non-recourse	5	408.5	370.3
Retractable preferred shares	7	325.0	325.0
Non-retractable equity preferred shares	7	210.0	209.5
Class A and Class B shareholders' equity			
Class A and Class B shares	8	505.9	511.2
Retained earnings	8	737.4	682.0
Foreign currency translation adjustment		2.1	2.7
		1,245.4	1,195.9
		$4,090.7	$3,936.6

C.O. Twa
Director

B.K. French
Director

Consolidated Statement of Changes in Cash Position

(Millions of Canadian Dollars)

Year Ended December 31

	1997	1996
Operating		
Earnings attributable to Class A and Class B shares	$ 181.5	$ 171.3
Non-cash items included in earnings		
Depreciation and depletion	192.7	186.0
Future income taxes	27.5	10.1
Other – net	(0.1)	15.6
Cash flow from operations	401.6	383.0
Change in non-cash working capital	(20.1)	52.2
	381.5	435.2
Dividends paid to Class A and Class B shareholders	(99.5)	(94.5)
	282.0	340.7
Investing		
Capital expenditures – net	(353.8)	(257.6)
Contributions by customers for extensions to utility plant	36.8	30.4
Sale of ATCOR Resources Ltd.	–	56.2
Other	(1.4)	3.8
	(318.4)	(167.2)
Financing		
Changes in notes payable	1.4	(94.4)
Issue of long term debt – recourse	68.5	14.0
– non-recourse	59.4	8.6
Repayment of long term debt – recourse	(56.3)	(62.7)
– non-recourse	(15.2)	(7.9)
Redemption of retractable preferred shares	–	(76.9)
Issue of non-retractable equity preferred shares	110.0	60.0
Redemption of non-retractable equity preferred shares	(109.5)	(55.0)
Issue (purchase) of Class A and Class B shares	(24.1)	7.0
Other	12.0	5.1
	46.2	(202.2)
Cash position[1]		
Increase (decrease)	9.8	(28.7)
Beginning of year	34.6	63.3
End of year	$ 44.4	$ 34.6

[1] Cash position includes cash and short term investments less current bank indebtedness.

Notes to Consolidated Financial Statements

December 31, 1997

(tabular amounts in millions of Canadian dollars)

1. Summary of Significant Accounting Policies

Financial Statement Presentation

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles and conform in all material respects with International Accounting Standards.

The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments ("Canadian Utilities"). The major subsidiaries are Alberta Power Limited (electric utility), CU Power International Limited (independent power producer), Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited (natural gas utilities), ATCO Gas Services Ltd. (natural gas gathering and processing) and Frontec Corporation (technical facilities management). Significant joint venture investments include Thames Power Limited, the McMahon Cogeneration Plant and the Osborne Cogeneration Plant.

Certain comparative figures have been reclassified to conform with the current presentation.

Utility Regulation

The electric and natural gas utility subsidiaries are regulated primarily by the Alberta Energy and Utilities Board ("EUB"), which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The EUB may award interim rates, subject to final determination.

Revenue Recognition

Utility revenues are recognized on the accrual basis and include an estimate of services provided but not yet billed.

Revenues resulting from the supply of contracted services are recorded by the percentage of completion method. Full provision is made for any anticipated loss.

The Electric Utilities Act ("EUA") provides for the sale of all power for use in Alberta to a power pool for resale to distribution companies at a bid price which matches demand with supply. Existing generating units can recover a return on investment and costs of production from the distribution companies. Over-recoveries can arise where pool prices exceed variable production costs and are repayable to the distribution companies. These cost recovery mechanisms apply to existing regulated generating units. New units which are brought into production will only receive pool prices.

Under provisions of the EUA, the electric subsidiary leases its transmission facilities to The Grid Company of Alberta, which administers transmission services needed to serve customers throughout Alberta and charges a uniform tariff to all distribution companies.

Natural Gas Supply

Natural gas supply expense is based on the forecast cost of natural gas included in customer rates. Variances from forecast costs are deferred until such time as approval from the EUB is obtained for refund to or collection from customers through revised rates and natural gas supply expense is adjusted accordingly.

Income Taxes

Each regulated electric and natural gas utility follows the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Property, Plant and Equipment

The utility subsidiaries include in capital expenditures an allowance for funds used during construction at rates approved by the EUB for debt and equity capital. Capital expenditures in the other subsidiaries include capitalized interest incurred during construction.

Certain utility additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate. Property, plant and equipment is disclosed net of unamortized contributions.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for utility assets are approved by the EUB. For certain utility assets these approved depreciation rates include a provision for future removal costs and site restoration costs. On retirement of depreciable utility assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Deferred Financing Charges

Expenses of the issue of long term debt are amortized over the weighted average life of the debt and expenses of the issue of preferred shares are amortized over the expected life of the issue. Unamortized premiums and issue costs of redeemed long term debt and preferred shares are amortized over the life of the issue funding the redemption.

Notes Payable

Under a bank loan agreement which is renewed on a continuing basis, Canadian Utilities may issue commercial paper or borrow directly from the bank. These borrowings allow Canadian Utilities to manage the amount and timing of long term debt, preferred share and equity issues and are classified as long term.

Long Term Debt Due Within One Year

When Canadian Utilities intends to refinance current maturities on a long term basis and there is a written undertaking from an underwriter to act on Canadian Utilities' behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then current maturities are classified as long term.

Hedging

In conducting its business, Canadian Utilities uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

Gains and losses are recognized in income in the same period and in the same financial statement category as the income or expense from the hedged position.

Retirement Benefits

Canadian Utilities has defined benefit pension plans covering approximately 85% of employees. Employees participate through contributions to the plans which provide for pensions based on length of service and final average earnings. The cost of pension benefits is determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Plan assets are valued at market adjusted for a three year averaging of unrealized gains or losses. Adjustments resulting from plan enhancements, experience gains and losses and changes in assumptions are amortized over the estimated average remaining service life of employees.

Canadian Utilities also has defined contribution pension plans for employees. Employer contributions are expensed as incurred.

The cost of other benefits, principally health, dental and life insurance for retirees and their dependents, is expensed as paid.

2. Income Taxes

Effective January 1, 1997, Canadian Utilities retroactively adopted the Canadian Institute of Chartered Accountants recommendations on accounting for income taxes for operations other than regulated electric and natural gas utilities. Under these recommendations, income taxes are accounted for using the liability method which is described in the Summary of Significant Accounting Policies. Previously, Canadian Utilities accounted for income taxes using the deferred method.

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	1997		1996	
Earnings before income taxes	$ 362.0	%	$ 353.2	%
Income taxes, at statutory rates	$ 161.5	44.6	$ 157.6	44.6
Dividends on retractable preferred shares	8.3	2.3	12.4	3.5
Allowance for funds used	(1.5)	(0.4)	(1.5)	(0.4)
Depreciation of capitalized allowance for funds used	3.6	1.0	3.6	1.0
Crown royalties and other non-deductible Crown payments	3.0	0.8	3.2	0.9
Earned depletion and resource allowance	(4.5)	(1.2)	(3.7)	(1.1)
Unrecorded future income taxes	(3.2)	(0.9)	(1.7)	(0.5)
Large Corporations Tax	4.3	1.2	4.6	1.3
Foreign tax rate variance	(3.8)	(1.1)	(2.6)	(0.7)
Change in future income taxes resulting from reduction in United Kingdom tax rate	(1.8)	(0.5)	–	–
Non-deductible interest on foreign financing	2.0	0.6	–	–
Other	0.2	–	0.9	0.3
	168.1	46.4	172.8	48.9
Current income taxes	140.3		147.8	
Future income taxes	$ 27.8		$ 25.0	

The future income tax liabilities comprise the following:

	1997	1996
Income and other taxes payable:		
Deferred natural gas costs and other	$ 0.3	$ 14.9
Future income taxes:		
Property, plant and equipment	$ 127.3	$ 78.0
Allowance for funds used	5.6	–
Deferred pension costs	2.2	0.5
Reserves	(7.8)	(9.3)
Tax loss carryforwards	(21.0)	(29.5)
Other	(2.3)	(1.6)
	$ 104.0	$ 38.1

In 1997, Alberta Power Limited received an EUB decision with respect to its general rate application for 1996 rates. As a consequence of this decision, $20.5 million of income and other taxes payable has been reclassified as future income taxes.

Unrecorded future income taxes of the utility subsidiaries increased by $3.2 million to $179.8 million at December 31, 1997.

The prior years' financial statements have not been restated for the change to accounting for income taxes using the liability method. The impact of this change in the current year is as follows:

	Increase (Decrease)
Statement of earnings	
Income tax expense	$ (2.3)
Earnings attributable to Class A and Class B shares	2.3
Direct charges to retained earnings	
Represents the cumulative increase in the income tax expense of prior years	(6.6)
Balance sheet	
Property, plant and equipment	10.3
Future income taxes	14.6

3. Direct Charges to Retained Earnings

	1997	1996
Purchase of Class A shares	$ 18.8	$ –
Adjustment to opening retained earnings for prior years' effect of change in method of accounting for income taxes	6.6	–
Stock options settled (after income taxes)	1.2	0.6
	$ 26.6	$ 0.6

4. Property, Plant and Equipment

	1997			1996	
	Composite Depreciation Rates	Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
Electric power	3.5%	$3,563.3	$1,098.7	$3,403.0	$ 999.8
Natural gas	4.0%	2,197.0	709.1	2,037.8	634.4
Other	6.4%	23.1	9.4	20.0	8.8
		$5,783.4	$1,817.2	$5,460.8	$1,643.0
Property, plant and equipment, less accumulated depreciation			$3,966.2		$3,817.8
Unamortized contributions by customers for extensions to utility plant			367.6		343.4
			$3,598.6		$3,474.4

Accumulated depreciation includes an amount provided for future removal and site restoration costs of $137.1 million (1996 – $114.4 million).

5. Long Term Debt

	1997	1996
Recourse (direct unsecured obligations)		
Debentures		
1982 Series 17.5% due March 1997 (sinking fund)	$ –	$ 21.0
1994 Medium Term Note 8.95% due July 1997	–	35.0
1988 Series 11.25% due September 1998	50.0	50.0
1995 Medium Term Note 7.55% due January 1999	42.0	42.0
1994 Medium Term Note 8.81% due April 2000	50.0	50.0
1997 Medium Term Note 5.42% due November 2002	68.0	–
1993 Series 7.25% due September 2003	60.0	60.0
1994 Series 8.73% due June 2004	100.0	100.0
1995 Series 8.43% due June 2005	125.0	125.0
1986 Series 9.85% due October 2006, redeemable October 1, 2001	100.0	100.0
1986 Second Series 10.25% due December 2006, redeemable December 12, 2001	90.0	90.0
1987 Series 12% due October 2007, redeemable October 15, 2002	125.0	125.0
1989 Series 10.20% due November 2009	125.0	125.0
1990 Series 11.40% due August 2010	125.0	125.0
1990 Second Series 11.77% due November 2020	100.0	100.0
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
	1,385.0	1,373.0
Other long term obligations, at rates from 4.1% to 12.0%	34.3	34.0
	$1,419.3	$1,407.0
Non-recourse (secured only by specific project and plant assets)		
Barking Power Limited project financing, due to 2010, payable in British pounds:		
At fixed rates averaging 7.95%	$ 116.6	$ 118.5
At London Interbank Offered Rate plus 0.5269%	196.3	202.5
McMahon cogeneration plant term facility, at 9.01%, due to 2004	25.2	29.1
Industrial Gas System credit facility, at 7.32%, due to 2006	31.5	26.7
Osborne Cogeneration Pty Ltd. project financing at 9.43%, due to 2013, payable in Australian dollars	55.1	8.7
	424.7	385.5
Less: Amounts due within one year	16.2	15.2
	$ 408.5	$ 370.3

The minimum annual repayments of long term debt for each of the next five years are as follows:

	Recourse	Non-Recourse	Total
1998	$ 51.7	$ 16.2	$ 67.9
1999	56.4	19.3	75.7
2000	50.2	21.8	72.0
2001	0.2	24.2	24.4
2002	85.8	25.9	111.7
	$ 244.3	$ 107.4	$ 351.7

Of the $67.9 million due in 1998, $51.7 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Redemption Privileges

Certain debentures of Canadian Utilities are redeemable prior to maturity on the dates specified above at the principal value plus accrued and unpaid interest.

Fair Values

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are shown below. Where market prices are not available, fair values are estimated using discounted cash flow analysis based on Canadian Utilities' current borrowing rate for similar borrowing arrangements.

	1997	1996
Recourse – fixed rate	$ 1,762.2	$ 1,687.8
– floating rate	18.5	18.2
	$ 1,780.7	$ 1,706.0
Non-recourse – fixed rate	$ 250.6	$ 189.4
– floating rate	196.3	202.5
	$ 446.9	$ 391.9

Osborne Cogeneration Pty Ltd. Project Financing

Canadian Utilities has a 50% interest in Osborne Cogeneration Pty Ltd., a company formed to develop a cogeneration plant near Adelaide, South Australia. Construction commenced in 1996 and is expected to be completed during 1998. A project financing term facility has been arranged for a total amount of $175.0 million AUD ($163.0 million).

Interest Expense

Interest expense on non-recourse debt is shown net of interest capitalized of $2.7 million (1996 – $0.3 million).

6. Notes Payable and Credit Lines

At December 31, 1997, Canadian Utilities had outstanding commercial paper of $5.3 million (1996 – $3.9 million), at an interest rate of 4.20%, maturing February 27, 1998.

Canadian Utilities has operating credit lines totalling $523.2 million, of which $261.7 million are available on a committed basis by the lenders and $261.5 million are available on an uncommitted basis. These credit lines enable Canadian Utilities to obtain short term financing for general business purposes. At December 31, 1997, there was outstanding $14.5 million under committed credit lines (1996 – $14.0 million) and $11.8 million under uncommitted credit lines (1996 – nil).

7. Preferred Shares

Authorized:

An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value	Retraction and Redemption Dates	1997 Shares	1997 Amount	1996 Shares	1996 Amount
	(dollars)					
Retractable						
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	December 1, 1998	5,000,000	$ 125.0	5,000,000	$ 125.0
5.3% Series R	$25.00	June 1, 1999	6,000,000	150.0	6,000,000	150.0
6.6% Series S	$25.00	March 1, 2000	2,000,000	50.0	2,000,000	50.0
				$ 325.0		$ 325.0
Non-retractable						
Cumulative Redeemable Preferred Shares						
5%			–	$ –	40,000	$ 4.0
4¼% Series			–	–	15,000	1.5
6% Series			–	–	50,000	5.0
				–		10.5
Cumulative Redeemable Second Preferred Shares						
7.3% Series C			–	–	732,480	18.3
7.7% Series L			–	–	604,570	15.1
7.1% Series N			–	–	699,533	17.5
8.0% Series P			–	–	1,923,733	48.1
				–		99.0
Perpetual Cumulative Second Preferred Shares						
5.4% Series O	$25.00	May 1, 1999	1,600,000	40.0	1,600,000	40.0
4.63% Series T	$25.00	December 2, 2001	1,600,000	40.0	1,600,000	40.0
4.63% Series U	$25.00	November 26, 2001	800,000	20.0	800,000	20.0
4.66% Series V	$25.00	October 3, 2002	4,400,000	110.0	–	–
				210.0		100.0
				$ 210.0		$ 209.5

On October 3, 1997, all of the outstanding 5%, 4 1/4% Series and 6% Series Cumulative Redeemable Preferred Shares were redeemed at a price of $104.00, $102.50 and $101.00 per share, respectively, plus accrued dividends and all of the outstanding Cumulative Redeemable Second Preferred Shares Series C, L, N and P were redeemed at a price of $25.00 per share plus accrued dividends.

On October 3, 1997, Canadian Utilities Limited issued $110.0 million of Perpetual Cumulative Second Preferred Shares Series V for cash. During the initial 5-year period, the dividend rate has been fixed at 4.66%. Thereafter, a new dividend rate may be established by negotiation between Canadian Utilities Limited and the holders of the shares.

The dividends payable on the Perpetual Cumulative Second Preferred Shares Series O, T and U are fixed until May 1, 1999, December 2, 2001 and November 26, 2001, respectively, at which time a new dividend rate may be established by negotiation between Canadian Utilities Limited and the holders of the shares.

Fair Values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are:

	1997	1996
Retractable	$ 330.7	$ 340.3
Non-retractable	$ 211.2	$ 215.1

Redemption and Retraction Privileges

The preferred shares of Canadian Utilities Limited may be redeemed at the stated value plus accrued and unpaid dividends. The Cumulative Redeemable Second Preferred Shares are retractable on the dates specified above at the option of the holder at the stated value plus accrued and unpaid dividends.

8. Class A and Class B Shares

	Class A Non-Voting		Class B Voting		Total	
	Shares	Consideration	Shares	Consideration	Shares	Consideration
Authorized	Unlimited		Unlimited			
Issued and Outstanding:						
December 31, 1995	39,656,023	$ 353.8	24,051,367	$ 150.4	63,707,390	$ 504.2
Issued	155,697	4.2	94,418	2.5	250,115	6.7
Stock options exercised	13,000	0.3	–	–	13,000	0.3
Converted: Class B to Class A	19,828	0.1	(19,828)	(0.1)	–	–
December 31, 1996	39,844,548	358.4	24,125,957	$ 152.8	63,970,505	$ 511.2
Purchased	(659,220)	(6.0)	–	–	(659,220)	(6.0)
Stock options exercised	28,400	0.7	–	–	28,400	0.7
Converted: Class B to Class A	31,284	0.2	(31,284)	(0.2)	–	–
December 31, 1997	39,245,012	$ 353.3	24,094,673	$ 152.6	63,339,685	$ 505.9

Shareholder Rights

The holders of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The holders of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, holders of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, holders of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling shareholder of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering. The complete text of the rights of exchange attached to the Class A non-voting shares is set out in a Certificate of Amendment dated September 10, 1982 issued to Canadian Utilities Limited.

Normal Course Issuer Bid

On May 2, 1997, Canadian Utilities Limited commenced a Normal Course Issuer Bid for the purchase of up to 5% of the outstanding Class A non-voting shares. The offer will expire on May 1, 1998.

Stock Option Plan

Canadian Utilities Limited has a stock option plan under which directors, officers and key employees may purchase Class A non-voting shares at $23.76 to $34.46 on or before February 1, 2005 to May 14, 2007. The exercise of the outstanding options would not materially dilute earnings per Class A and Class B share. Changes in shares under option are summarized below:

	1997	1996
Options at beginning of year	742,000	675,000
Granted	258,000	155,000
Exercised	(28,400)	(13,000)
Settled	(152,500)	(75,000)
Options at end of year	819,100	742,000

Retained Earnings

The debenture trust indenture places certain limitations on Canadian Utilities which include restrictions on the payment of dividends on Class A non-voting and Class B common shares. Consolidated retained earnings in the amount of $218.4 million are free from such restrictions.

9. Joint Ventures

Canadian Utilities' interest in joint ventures is summarized below:

	1997	1996
Statement of earnings		
Revenues	$ 188.8	$ 167.6
Operating expenses	115.7	100.0
Depreciation	15.5	14.8
Financing charges and other	22.1	26.0
Earnings from joint ventures before income taxes	$ 35.5	$ 26.8
Balance sheet		
Current assets	$ 95.9	$ 68.0
Current liabilities	(69.2)	(57.9)
Property, plant and equipment	456.6	410.7
Deferred items – net	(50.4)	(36.4)
Long term debt – non-recourse	(378.7)	(345.3)
Investment in joint ventures	$ 54.2	$ 39.1
Statement of changes in cash position		
Operating	$ 45.7	$ 36.2
Investing	(66.3)	(13.4)
Financing	21.8	(49.8)
Increase (decrease) in cash position	$ 1.2	$ (27.0)

Current assets include cash of $35.1 million (1996 – $34.6 million) which is only available for use within the joint ventures.

Non-recourse debt is secured only by joint venture assets.

10. Related Party Transactions

In the normal course of business with its parent corporation, ATCO Ltd., and affiliated companies, Canadian Utilities incurred administrative expenses and licensing fees totalling $2.0 million (1996 – $2.6 million) and recovered administrative expenses and business development costs totalling $1.9 million (1996 – $0.3 million).

11. Retirement Benefits

	1997	1996
Pension costs:		
Expensed (recovered)	$ (7.3)	$ 9.2
Capitalized	(0.1)	2.0
	(7.4)	11.2
Other retirement benefits expensed	1.3	1.2
	$ (6.1)	$12.4
Corporate contributions:		
Pensions	$ 2.3	$ 3.8
Other retirement benefits	1.3	1.2
	$ 3.6	$ 5.0
Net change in deferred pension asset	$ 9.7	$ (7.4)

The cumulative excess of contributions over costs of $12.5 million (1996 – $2.8 million) is included in other assets.

The present value of the accrued pension benefits based on actuarial calculations and the net assets available to provide for pensions under the defined benefit plan are as follows:

	1997	1996
Market value of assets	$1,058.0	$ 935.0
Accrued pension benefits	748.6	716.8
Surplus	$ 309.4	$ 218.2

12. Commitments and Contingencies

Minimum operating lease payments, which extend over periods not exceeding 14 years, are as follows:

1998	1999	2000	2001	2002	Total of All Subsequent Years
$11.2	$11.1	$10.3	$9.8	$9.7	$32.1

Canadian Utilities is party to a number of disputes and lawsuits in the normal course of business. Management is confident that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

In late 1997, Canadian Western Natural Gas Company Limited initiated a negotiated settlement process with its customers to establish 1997 capital structure and return on equity and 1998 rates. An agreement and approval by the EUB is expected in 1998.

13. Segmented Information

Business Segments

1997 1996	Electric Power	Natural Gas	Technical Facilities Management	Corporate and Other	Consolidated [1]
Revenues	$ 837.7	$ 994.7	$ 98.2	$ 12.3	$ 1,927.6
	$ 811.7	$ 912.6	$ 89.3	$ 14.7	$ 1,813.1
Operating expenses	402.6	719.0	86.9	15.8	1,209.0
	384.7	623.4	77.4	15.8	1,086.1
Depreciation and depletion	113.4	77.8	1.2	0.3	192.7
	113.1	70.9	1.1	0.9	186.0
Financing charges and other	115.2	54.6	(1.1)	(4.8)	163.9
	127.5	62.9	(0.6)	(2.0)	187.8
Earnings before income taxes	$ 206.5	$ 143.3	$ 11.2	$ 1.0	$ 362.0
	$ 186.4	$ 155.4	$ 11.4	$ –	$ 353.2
Total assets	$ 2,570.7	$ 1,473.5	$ 39.4	$ 11.4	$ 4,090.7
	$ 2,487.5	$ 1,413.8	$ 32.5	$ 9.3	$ 3,936.6
Capital expenditures	$ 189.0	$ 153.8	$ 1.4	$ 2.7	$ 346.9
	$ 139.5	$ 111.6	$ 1.2	$ –	$ 252.3

[1] Inter-segment transactions have been eliminated in the consolidated column.

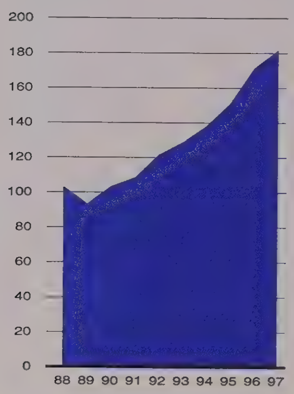
Geographic Segments

	Domestic		Foreign		Consolidated	
	1997	1996	1997	1996	1997	1996
Revenues	$ 1,765.9	$ 1,669.2	$ 161.7	$ 143.9	$ 1,927.6	$ 1,813.1
Earnings before income taxes	$ 331.4	$ 331.5	$ 30.6	$ 21.7	$ 362.0	$ 353.2
Total assets	$ 3,587.1	$ 3,494.2	$ 503.6	$ 442.4	$ 4,090.7	$ 3,936.6
Capital expenditures	$ 287.1	$ 238.6	$ 59.8	$ 13.7	$ 346.9	$ 252.3

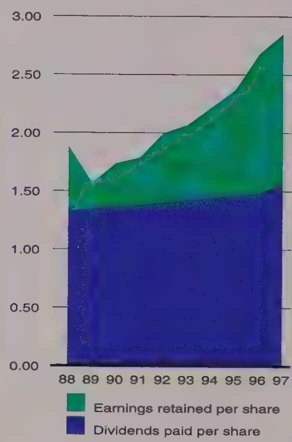
Foreign activities consist of investment in, and operations of, the Barking Power Plant in the United Kingdom, maintenance of the Alaska Radar System and investment in the Osborne Cogeneration Plant in Australia.

Consolidated Ten Year Financial Summary

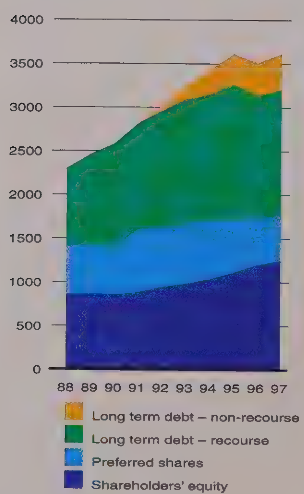
EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES
(millions of dollars)



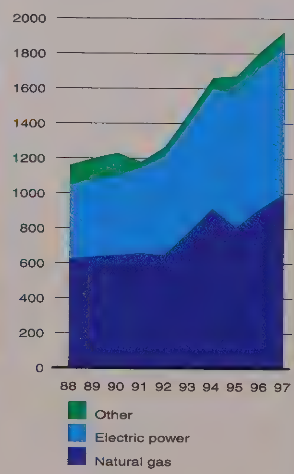
EARNINGS PER CLASS A AND CLASS B SHARE
(dollars)



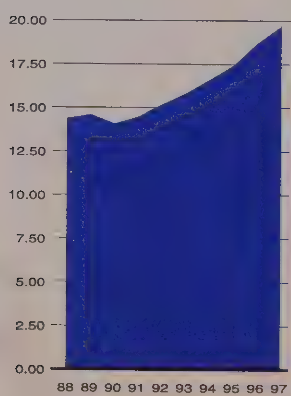
CAPITALIZATION
(millions of dollars)



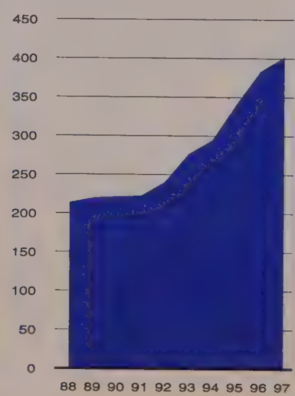
REVENUES
(millions of dollars)



EQUITY PER SHARE
(dollars)



CASH FLOW FROM OPERATIONS
(millions of dollars)



(Dollars in millions, except as indicated)

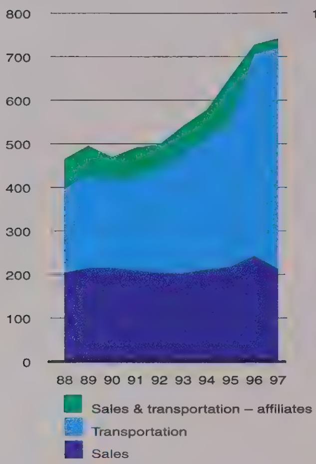
EARNINGS		
Revenues (excluding inter-segment)	Electric power	
	Natural gas	
	Technical facilities management	
	Non-utility oil and gas	
	Corporate and other	
Costs and expenses	Natural gas supply	
	Fuel and purchased power	
	Operation and maintenance	
	Depreciation and depletion	
	Franchise, property and other taxes	
Financing charges and other	Interest expense - recourse debt	
	- non-recourse debt	
	Dividends on retractable preferred shares	
	Allowance for funds used	
	Interest and other income	
Earnings before income taxes		
Income taxes		
Net earnings		
Dividends on non-retractable equity preferred shares		
Earnings attributable to Class A and Class B shares		
SEGMENTED EARNINGS		
Electric power		
Natural gas		
Technical facilities management		
Non-utility oil and gas		
Corporate and other		
CASH FLOWS		
Operations		
Class A and B dividends		
Capital expenditures - net		
Financing		
CLASS A & B SHARES		
Shares outstanding* (thousands)		At end of year
		Weighted average for year
Return on equity* (earnings attributable / weighted average equity)		
Earnings per share* ($) (earnings attributable / weighted average shares)		
Dividends paid per share* ($)		
Equity per share* ($) (shareholders' equity / end of year shares)		
Stock market record - Class A non-voting shares		High
		Low
		Close
		Daily trading volume
Stock market record - Class B common shares		High
		Low
		Close
		Daily trading volume
OTHER FINANCIAL INDICATORS		
Payout ratio (dividends / earnings attributable)		
Interest coverage (pretax)		
BALANCE SHEET		
Property, plant, and equipment		– gross
		– net
Total assets		
Capitalization		
	Notes payable and long term debt - recourse	
	Long term debt - non-recourse	
	Retractable preferred shares	
	Non-retractable equity preferred shares	
	Shareholders' equity*	
Total capitalization		
Capitalization ratios - year end		
	Notes payable and long term debt - recourse	
	Long term debt - non-recourse	
	Retractable preferred shares	
	Non-retractable equity preferred shares	
	Shareholders' equity*	

* *Includes Class A non-voting and Class B common shares.*

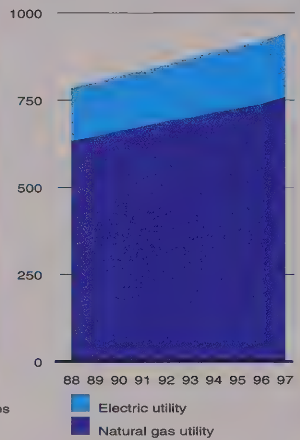
	1997	1996	1995	1994	1993	1992	1991	1990	1989	1988
	837.5	811.5	770.8	688.0	625.2	568.0	491.4	455.6	442.3	427.4
	993.1	912.0	805.4	913.3	776.1	647.1	656.7	646.5	636.4	622.9
	96.5	88.9	97.1	55.7	57.5	49.1	30.1	22.4	10.4	1.5
	–	–	–	–	–	–	–	104.6	107.3	106.9
	0.5	0.7	0.7	5.5	1.8	4.0	3.2	3.0	4.0	1.9
	1,927.6	1,813.1	1,674.0	1,662.5	1,460.6	1,268.2	1,181.4	1,232.1	1,200.4	1,160.6
	400.8	311.1	275.8	409.9	328.3	240.6	272.2	291.6	294.5	284.1
	193.8	175.6	164.1	126.7	88.8	87.6	75.9	65.5	61.2	65.6
	510.5	500.8	467.3	394.4	367.9	350.5	316.2	353.7	347.9	315.4
	192.7	186.0	170.8	159.3	142.0	124.2	107.3	114.5	126.4	102.3
	103.9	98.6	93.5	98.8	88.8	76.1	74.0	71.0	67.3	61.8
	1,401.7	1,272.1	1,171.5	1,189.1	1,015.8	879.0	845.6	896.3	897.3	829.2
	138.6	150.4	153.3	150.2	144.5	138.9	137.3	127.4	108.5	103.6
	34.1	30.8	22.4	0.2	–	–	–	–	–	–
	18.6	27.8	31.6	32.3	33.1	37.0	40.7	37.7	37.8	37.8
	(6.7)	(6.6)	(6.6)	(4.0)	(5.0)	(23.2)	(36.2)	(32.6)	(27.8)	(20.5)
	(20.7)	(14.6)	(9.4)	(5.0)	(7.2)	(11.6)	(5.1)	(2.2)	(4.2)	(3.5)
	163.9	187.8	191.3	173.7	165.4	141.1	136.7	130.3	114.3	117.4
	362.0	353.2	311.2	299.7	279.4	248.1	199.1	205.5	188.8	214.0
	168.1	172.8	149.5	148.8	131.8	110.0	82.4	97.8	90.9	106.9
	193.9	180.4	161.7	150.9	147.6	138.1	116.7	107.7	97.9	107.1
	12.4	9.1	10.5	12.7	18.8	16.5	8.1	4.2	4.4	4.3
	181.5	171.3	151.2	138.2	128.8	121.6	108.6	103.5	93.5	102.8
	104.8	88.7	91.2	83.3	77.4	81.4	70.5	62.9	65.9	57.6
	74.4	79.6	61.7	57.4	49.0	38.8	38.7	35.6	37.1	43.1
	6.1	6.5	6.8	5.4	6.3	3.6	1.2	0.6	(0.6)	–
	–	1.5	0.5	1.9	2.3	3.4	2.2	4.1	(9.2)	2.7
	(3.8)	(5.0)	(9.0)	(9.8)	(6.2)	(5.6)	(4.0)	0.3	0.3	(0.6)
	181.5	171.3	151.2	138.2	128.8	121.6	108.6	103.5	93.5	102.8
	401.6	383.0	340.8	294.8	276.8	240.4	222.6	221.7	219.8	213.7
	99.5	94.5	92.4	89.5	88.2	85.2	83.9	81.2	80.0	71.9
	353.8	257.6	329.0	309.6	392.9	376.1	322.9	348.9	322.1	249.0
	46.2	(202.2)	165.1	100.7	168.6	167.5	202.6	182.8	144.3	118.2
	63,340	63,971	63,707	62,132	62,121	62,091	60,825	60,818	59,519	59,433
	63,714	63,940	63,695	62,132	62,112	60,940	60,824	59,586	59,485	54,813
	14.8%	14.8%	14.0%	13.7%	13.4%	13.5%	12.5%	11.8%	10.9%	13.7%
	2.85	2.68	2.37	2.22	2.07	2.00	1.79	1.74	1.57	1.88
	1.56	1.48	1.46	1.44	1.42	1.40	1.38	1.365	1.345	1.325
	19.66	18.70	17.42	16.62	15.83	15.18	14.48	14.08	14.60	14.37
	41.25	34.50	26.25	27.00	26.88	23.00	21.38	22.00	22.38	20.38
	30.40	25.13	21.88	21.88	20.25	18.75	18.63	18.25	18.75	18.00
	40.65	30.55	26.00	24.00	25.63	20.50	20.75	20.38	21.88	19.63
	23,874	28,701	25,106	18,748	37,837	38,687	30,058	13,134	35,857	15,125
	41.20	34.50	26.25	27.38	26.88	23.00	21.75	22.00	22.38	20.50
	30.65	25.50	22.00	23.13	20.38	18.75	18.63	18.25	18.75	18.50
	40.70	30.10	26.00	24.13	25.63	20.75	21.38	20.50	22.00	19.50
	6,967	1,441	8,311	3,589	6,568	7,234	4,439	5,432	12,515	9,384
	55%	55%	61%	65%	69%	70%	77%	79%	86%	70%
	3.20	3.10	2.95	3.21	3.17	3.05	2.75	2.91	3.10	3.43
	5,783.4	5,460.8	5,200.6	4,928.7	4,631.7	4,271.5	3,939.2	3,640.6	3,628.2	3,322.3
	3,598.6	3,474.4	3,397.8	3,274.3	3,121.9	2,884.6	2,662.0	2,468.7	2,432.4	2,265.6
	4,090.7	3,936.6	3,906.2	3,680.3	3,517.8	3,236.9	2,996.3	2,799.8	2,707.3	2,504.5
	1,424.6	1,410.9	1,553.9	1,423.5	1,425.3	1,318.9	1,210.3	1,192.6	1,036.3	883.1
	408.5	370.3	345.9	282.6	157.9	60.5	–	–	–	–
	325.0	325.0	450.0	550.0	410.0	485.4	512.4	486.2	487.8	487.8
	210.0	209.5	156.4	139.0	270.1	213.9	213.9	50.0	68.9	71.8
	1,245.4	1,195.9	1,109.8	1,033.0	983.4	942.4	880.6	856.1	869.0	854.0
	3,613.5	3,511.6	3,616.0	3,428.1	3,246.7	3,021.1	2,817.2	2,584.9	2,462.0	2,296.7
	39%	40%	43%	42%	44%	44%	43%	46%	42%	39%
	11%	11%	9%	8%	5%	2%	–	–	–	–
	9%	9%	13%	16%	13%	16%	18%	19%	20%	21%
	6%	6%	4%	4%	8%	7%	8%	2%	3%	3%
	35%	34%	31%	30%	30%	31%	31%	33%	35%	37%

Consolidated Ten Year Operating Summary

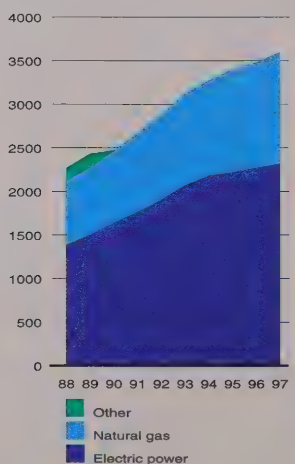
NATURAL GAS SYSTEM THROUGHPUT
(petajoules)



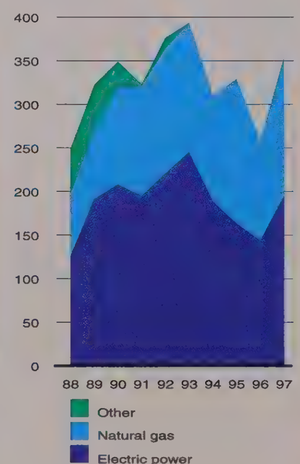
GAS AND ELECTRIC CUSTOMERS AT YEAR END
(thousands)



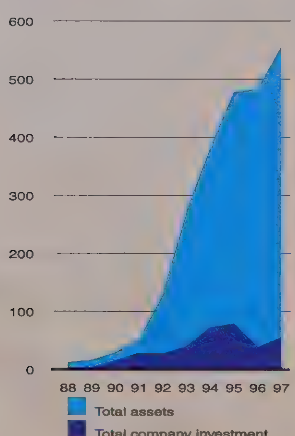
PROPERTY, PLANT AND EQUIPMENT (NET)
(millions of dollars)



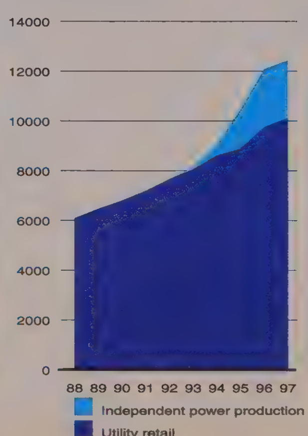
CAPITAL EXPENDITURES (NET)
(millions of dollars)



JOINT VENTURE OPERATIONS
(millions of dollars)



ELECTRIC SALES
(millions of kilowatt hours)



(Dollars in millions, except as indicated)
Electric Utility
Property, plant and equipment – gross
Accumulated depreciation
Unamortized contributions for extensions to plant
Property, plant and equipment – net
Growth over prior year
Capital expenditures - net
Generating capacity (thousands of kilowatts)
Maximum hourly demand (thousands of kilowatts)
Power lines (thousands of kilometres)
Retail sales (millions of kilowatt hours)
Growth over prior year
Average annual use per residential customer (kWh)
Average annual billing per residential customer ($)
Customers at year end (thousands)
Natural Gas Utility
Property, plant and equipment – gross
Accumulated depreciation
Unamortized contributions for extensions to plant
Property, plant and equipment – net
Growth over prior year
Capital expenditures - net
Pipelines (thousands of kilometres)
Maximum daily demand (terajoules)
Sales (petajoules)
Transportation (petajoules)
Sales and transportation - affiliates (petajoules)
Total system throughput (petajoules)
Growth over prior year
Average annual use per residential customer (gigajoules)
Average annual billing per residential customer ($)
Degree days – Edmonton *
Degree days – Calgary **
Customers at year end (thousands)

* *Degree days – Edmonton – are defined as the difference of the mean daily temperature fro*

** *Degree days – Calgary – are defined as the difference of the mean daily temperature from*

1997	1996	1995	1994	1993	1992	1991	1990	1989	1988
3,061.2	2,962.6	2,848.7	2,747.9	2,665.1	2,550.8	2,440.5	2,278.0	2,076.5	1,892.9
1,053.9	971.1	881.3	800.8	723.7	646.2	583.9	529.0	468.5	413.5
150.0	136.6	129.2	121.3	117.8	112.5	111.1	110.6	107.4	96.1
1,857.3	1,854.9	1,838.2	1,825.8	1,823.6	1,792.1	1,745.5	1,638.4	1,500.6	1,383.3
0%	1%	1%	0%	2%	3%	7%	9%	8%	5%
127.0	129.7	121.3	102.1	111.1	126.4	177.6	207.9	191.1	125.0
1,452	1,446	1,446	1,439	1,436	1,427	1,425	1,424	1,232	1,235
1,324	1,331	1,454	1,313	1,292	1,284	1,183	1,235	1,135	1,055
54.9	53.9	53.1	51.3	50.0	49.0	48.4	47.9	46.8	45.5
10,089	9,760	8,886	8,595	8,035	7,660	7,188	6,799	6,467	6,083
3%	10%	3%	7%	5%	7%	6%	5%	6%	12%
7,381	7,743	7,479	7,573	7,522	7,352	7,742	7,689	7,577	7,360
784	807	784	789	768	691	675	608	556	582
183.3	179.8	176.8	174.0	171.1	160.9	159.0	157.0	154.6	152.5
2,080.2	1,941.6	1,875.3	1,773.1	1,670.8	1,577.8	1,468.9	1,352.5	1,255.0	1,184.7
695.5	626.5	570.7	529.2	481.4	447.3	414.1	372.9	341.5	305.0
211.9	201.1	191.8	186.5	175.8	172.7	162.8	155.6	147.3	138.8
1,172.8	1,114.0	1,112.8	1,057.4	1,013.6	957.8	892.0	824.0	766.2	740.9
5%	0%	5%	4%	6%	7%	8%	8%	3%	3%
147.5	83.6	131.0	119.3	128.6	131.7	124.7	111.9	78.5	73.3
39.8	38.8	38.4	37.6	37.0	36.9	36.3	35.3	34.8	34.4
2,791	2,821	2,650	2,335	2,292	2,482	2,308	2,388	2,524	2,062
212	242	217	211	203	203	209	215	214	203
508	464	337	302	277	237	221	194	217	194
21	21	100	65	61	58	61	60	64	68
741	727	654	578	541	498	491	469	495	465
2%	11%	13%	7%	9%	1%	5%	(5%)	7%	13%
148	175	157	154	152	149	154	161	161	148
677	648	602	695	620	514	524	535	532	497
3,964	5,018	4,322	4,274	3,864	3,863	3,875	4,127	4,191	3,648
5,031	6,018	5,324	5,030	5,049	4,778	4,790	4,968	5,173	4,493
756.6	738.1	725.2	713.8	698.8	689.1	673.2	661.3	644.7	631.5

ees Celsius.

elsius.

Corporate Structure

Directors and Officers

Board of Directors

W. L. Britton, Q.C. [1]
Partner
Bennett Jones Verchere
Calgary, Alberta

B.P. Drummond
Corporate Director
Montreal, Quebec

B. K. French [2][3]
President
Karusel Management Ltd.
Calgary, Alberta

V. L. Horte
President
V.L. Horte Ventures Inc.
Calgary, Alberta

W. R. Horton [2]
Corporate Director
Winfield, B.C.

H. E. Joudrie [1]
Chairman of the Board
Gulf Canada Resources Limited
Toronto, Ontario

R.W.A. Laidlaw [1]
Corporate Director
Calgary, Alberta

Rt. Hon. D.F. Mazankowski,
P.C., D.Eng., LL.D. [1]
Corporate Director
Vegreville, Alberta

H.M. Neldner [2][4]
Corporate Director
Edmonton, Alberta

L. R. Shaben [3]
Chairman
Western New Ventures
Capital Corporation
Edmonton, Alberta

R. B. Sirkis
Partner
Bennett Jones Verchere
Calgary, Alberta

N. C. Southern [2]
Deputy Chairman of the Board
Canadian Utilities Limited

R. D. Southern,
C. M., C.B.E., LL.D.
Chairman of the Board
and Chief Executive Officer
Canadian Utilities Limited
Calgary, Alberta

D. L. Tait, F.R.I., F.C.A. [2][3]
President
Tait Management Services Ltd.
Lethbridge, Alberta

C.O. Twa
President and
Chief Operating Officer
Canadian Utilities Limited
Calgary, Alberta

(1) *member of the Corporate Governance - Nomination, Succession and Compensation Committee*

(2) *member of the Audit Committee*

(3) *Member of the Risk Review Committee*

(4) *Member of the Pension Fund Committee*

Officers

R. D. Southern
Chairman of the Board
and Chief Executive Officer

N. C. Southern
Deputy Chairman of the Board

C. O. Twa
President and
Chief Operating Officer

J. A. Campbell
Senior Vice President, Finance
and Chief Financial Officer

D. R. Cawsey
Assistant Corporate Secretary
and Manager, Human Resources

D. T. Davis
Vice President, Internal Audit

D. M. Ellard
Vice President

P. J. House
Vice President, Corporate Secretary

S.W. Kiefer
Vice President,
Information Technology

C. S. McConnell
Treasurer

L. J. Vegh
Vice President, Insurance

K. M. Watson
Vice President, Controller

S. R. Werth
Vice President, Administration

Presidents of Principal Operating Subsidiaries

G. K. Bauer
President
CU Power International Limited

J. R. Frey
President
Alberta Power Limited

J. D. Graham
President
Canadian Western Natural Gas
Company Limited

G. N. Paicu
President and
Chief Executive Officer
Frontec Corporation

M. M. Shaw
President
ATCO Gas Services Ltd.

C. K. Sheard
President
Northwestern Utilities Limited

Corporate Information

CANADIAN UTILITIES LIMITED OPERATING COMPANIES

Electric Power

Alberta Power Limited
The Yukon Electrical Company Limited
Northland Utilities (NWT) Limited
Northland Utilities (Yellowknife) Limited
CU Power Australia Pty Ltd.
CU Power International Limited
CU Power Canada Limited
CU Power Generation Limited
Thames Power Limited
Barking Power Limited
Thames Power Services Limited
Thames Valley Power Limited

Natural Gas

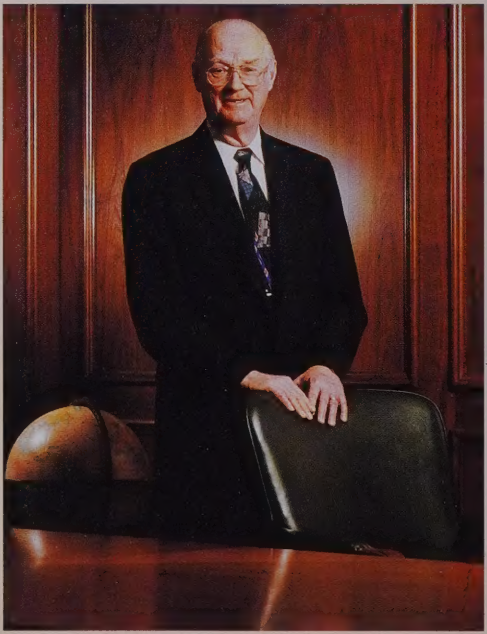
ATCO Gas Services Ltd.
Canadian Western Natural Gas Company Limited
Northwestern Utilities Limited
CU Water Limited

Technical Services & Facilities Management

Frontec Corporation
Frontec Logistics Corp.
Frontec Services Limited
ATCO Travel Ltd.
Frontec Property Management
Narwhal Arctic Services
Torngait Services Inc.
Uqsuq Corporation

CORPORATE HEAD OFFICE

1500, 909 - 11th Avenue S.W.
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Fax: (403) 292-7643



CAMERON S. RICHARDSON

It is with a great sense of sorrow that all Directors, Officers and people of the ATCO Group, together with a host of people around the world, reflect on the passing of Mr. Cameron S. Richardson.

Cam Richardson, who began his career with ATCO Group in 1959 and retired in 1997 – a Director; Senior Vice President, Finance & Chief Financial Officer of ATCO Ltd. and Canadian Utilities Limited – passed away on January 28, 1998 in Calgary, Alberta.

His contributions to our company's success, to the people who make up our endeavours, and to our customers are legendary.

On behalf of all his friends and colleagues, we offer to his loving wife Dale and his family, our heartfelt condolences.

Shareholders' Information

INCORPORATION

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING

The annual meeting of shareholders will be held at 10:00 a.m., Wednesday, May 13, 1998 at Hotel Macdonald, Edmonton, Alberta.

AUDITORS

Price Waterhouse
Calgary, Alberta

COUNSEL

Bennett Jones Verchere
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

Class A non-voting and
Class B common shares
and Second Preferred
(Series Q, R and S) Shares
CIBC Mellon Trust Company
Montreal/Toronto/Calgary/Vancouver

TRUSTEE AND REGISTRAR

Debentures
National Trust Company
by its agent
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/
Calgary/Vancouver

STOCK EXCHANGE LISTINGS

	Symbol	Listing
Class A non-voting	CU	Toronto, Montreal, Alberta
Class B common	CU.X	Toronto, Montreal, Alberta

Cumulative Redeemable Second Preferred Shares

	Symbol	Listing
5.90% Series Q	CU.PR.T	Toronto, Montreal
5.30% Series R	CU.PR.V	Toronto, Montreal
6.60% Series S	CU.PR.D	Toronto, Montreal

ATCO GROUP ANNUAL REPORTS

Annual Reports to Shareholders and Management's Discussion and Analysis for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
1500, 909 - 11th Avenue S.W.
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500

SHAREHOLDER INQUIRIES

Dividend information and other inquiries concerning shares should be directed to:

CIBC Mellon Trust Company
Stock Transfer Department
600 The Dome Tower
333 - 7th Avenue, S.W.
Calgary, Alberta T2P 2Z1
Telephone 1-800-387-0825
(toll-free in Canada or U.S.A.)

CANADIAN UTILITIES LIMITED

An ATCO Company

Printed in Canada